STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 7533

Establishment of Price for Standard Offer under the	)	
Sustainably Priced Energy Enterprise Development	)	Hearings at
("SPEED") program	)	Montpelier, Vermont
		December 1- 4, 2009

Order entered:

PRESENT: George Young, Esq. (Hearing Officer)
J. Riley Allen (Hearing Officer)
Ed McNamara, Esq., PSB
Mary Jo Krolewski, PSB

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1. Active participants that attended hearings.

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I. Introduction

In 2009, the Vermont General Assembly passed Act 45,[3] which mandated the establishment of a standard offer for a limited amount of qualifying SPEED resources with a plant capacity of 2.2 MW or less.[4] The legislation included initial prices to be paid qualifying plant owners but charged the Vermont Public Service Board ("Board") with setting an interim price no later than September 15, 2009, and a final price no later than January 15, 2010. The Board established interim prices on September 15, 2009, in Docket 7523.[5] With this proposed decision, we recommend inputs toward establishing final prices in Docket 7533.[6] This PFD sets out the Hearing Officers' recommendations to the Board on all outstanding issues that were unresolved or required determinations based on guidance provided.

This PFD does not recommend specific prices, however. Instead, we delineate the parameters that the parties should use as inputs into the pricing model that was developed during the course of the proceeding. We also recommend that the Board accept the model as the framework for setting prices. The model requires a significant number of assumptions to determine the standard-offer prices. To the extent that we do not specifically address certain assumptions in this PFD, we recommend that the assumptions contained in the model be approved.

3. Public Act No. 45 (2009 Vt., Bien. Sess.), codified in 30 V.S.A. § 8005.

4. Sections 8001 *et seq*, set out the Sustainably Priced Energy Enterprise Development or "SPEED" program.

5. Docket 7523, *Implementation of Standard Offer Prices for Sustainably Priced Energy Enterprise Development (SPEED) resources Re: Interim Prices.*

6. The Board has previously determined that this proceeding is not a contested case. Therefore, normal contested case procedures do not apply, including the requirement that the Hearing Officers issue a Proposal for Decision ("PFD"). Nonetheless, the Hearing Officers decided earlier to establish the standard-offer prices in this docket based upon evidence submitted during hearings. In addition, the Hearing Officers notified parties that they would distribute a PFD for comment, even though it may not be statutorily required.

In conjunction with the release of this PFD we ask the Board's Independent Witness, John Dalton,[7] to generate model runs incorporating these inputs and release the results immediately for review and comment by other participants in this proceeding. Both the model and the model runs will be posted to the Board's web site, and will be distributed to the participants through the group e-mail list dedicated to this proceeding.

The resulting standard-offer price determinations apply during the next two years of the program (through January 15, 2012)[8] unless altered by the Board under an earlier determination.

Next Steps

This Proposal for Decision sets forth proposed assumptions to use in the model and resolves any issues associated with the design of the model. The Board's Independent Witness will run the model using the assumptions contained in this PFD and will distribute the results to participants.[9] The participants will then have an opportunity to comment on both our determination and the modeling results of Mr. Dalton. Comments on both the Proposal for Decision and the effort of Mr. Dalton to properly incorporate those results are then due on January 11. The Board will then issue an order setting the prices, after consideration of this PFD, the modeling results provided by the Board's Independent Witness, and the comments of participants.

II. STATUTORY AND PROCEDURAL HISTORY

A. Background

In 2005, the Vermont General Assembly established the SPEED program to encourage the development of renewable energy resources in Vermont, as well as the purchase of renewable

7. The Board hired John Dalton of Power Advisory, LLC to serve as an independent witness regarding the assumptions used in the model, and also to assist with refining the model.

8. Pursuant to § 8005(b)(2)(C), the Board must readjust the standard-offer price at least every two years.

9. Pursuant to Vermont case law, the Board may not perform these calculations itself. *In re Petition of Twenty-Four Vermont Utilities*, 159 Vt. 339, 350–351, 618 A.2d 1295, 1302–1303 (1992).

power by the State's electric distribution utilities.[10] In response to the legislation, the Board promulgated Board Rule 4.300 to implement the SPEED program. Board Rule 4.300 also established a SPEED Facilitator to encourage the development of resources under the program.

On May 27, 2009, the Vermont Energy Act of 2009 took effect; the Act substantially modifies the SPEED program. It establishes a standard-offer mechanism for potential project developers seeking a market for the energy produced from qualifying SPEED resources. The Act establishes default prices for the standard offer for different technologies, and enunciates largely cost-based criteria for determining the price paid to developers of renewable power purchased through the SPEED program. Pursuant to the Act, the SPEED Facilitator is required to purchase, on behalf of the Vermont electric distribution utilities, energy from developers who accept the standard offer. The energy, and attendant costs, are assigned to the utilities based on their pro rata share of total Vermont retail kWh sales for the previous calendar year.[11]

The Act required the Board to determine by September 15, 2009, whether there was a "substantial likelihood" that one or more of the default prices in the statute do not constitute a "reasonable approximation" of the prices applying the largely cost-based criteria in the statute. If the Board determined that the statutory prices did not constitute a reasonable approximation, the Act required the Board to set interim prices. On September 15, 2009, the Board issued an Order setting the interim prices, based largely on the statutory defaults. The exception was for farm methane, which was set at 16 cents/kWh compared to a statutory default rate of 12.5 cents.[12]

Act 45 further required that the Board set, no later than January 15, 2010, the price to be paid to plant owners under a standard-offer following an opportunity for more detailed analysis. Today's Order fulfills that requirement.

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10. The SPEED program is codified in 30 V.S.A. § 8005.

11. Section 8005(b)(7) allows an exception to the purchase power requirements of subdivision (5) if the retail electricity provider establishes that it receives at least 25 % of its energy from qualifying SPEED resources that were in operation on or before September 30, 2009.

12. All prices were set based on nominal levelized values. For landfill methane, the price was set at 12 cents/kWh. For small wind (15 kW or less) the price was set at 20 cents/kWh. For large wind (over 15kW), hydro-power, and biomass, the price was set at 12.5 cents/kWh. For solar PV, the price was set at 30 cents/kWh.

B. Procedural History

On June 29, 2009, the Board opened an investigation into the establishment of prices for the standard-offer program. In that Order, we stated:

> The investigation is intended to build upon the record developed in Docket 7523, resolve all necessary implementation issues not addressed in that docket, and reevaluate the prices for SPEED projects set out in the statute. We open this investigation as a distinct proceeding primarily because the Act requires that the Board not only open the non-contested case docket that is Docket No. 7523, but also complete it by September 15, 2009. To meet this mandate, we intend to close that docket following completion of the tasks set out in Section 8005(b)(2)(B)(ii). To ensure that we can deal with any implementation issues that are not fully resolved and to avoid having to duplicate the gathering and evaluation of information that occurs in that docket, we intend to incorporate the record from that docket as it now exists plus any additional material subsequently generated therein.

To the extent feasible, the process we have used to establish the standard-offer prices by the January 15 deadline has been largely independent of the process used to set the September 15 prices. We have incorporated two documents from the September 15 price-setting process into the evidentiary record in this Docket, one of which was prepared by a witness in this proceeding. The majority of the information upon which we have relied was developed in this Docket and sponsored by witnesses who testified during evidentiary hearings and were subject to normal discovery and cross-examination.

A status conference was held on October 15, 2009, to discuss the hearing process and other procedural matters.

Technical hearings were held December 1 through December 4, 2009.

Initial briefs were filed on December 16, 2009, with reply briefs filed on December 22, 2009.

III. Context for Price Determinations Required under Act 45

A. Least Cost Principles/Assumptions Regarding Efficient Inputs

Findings

1. The standard offer program should send a price signal that incents the development of efficient renewable energy projects that are located at sites with favorable renewable energy

resources and employ among the most efficient eligible renewable energy technologies. Dalton pf. reb. at 28.

2. The standard offer rates should be developed based on the most cost-efficient size within each technology type. Lamont pf. at 3.

3. The rates should also be based on a well located (i.e., adequate transmission support) site with above average resource availability. Lamont pf. at 3.

Discussion

The establishment of the standard-offer prices in this proceeding is guided by standards set out in Title 30, in particular Section 8005(b)(2). The parties disagree, however, on how the Board should interpret the statutory language. In large part, this disagreement relates to how the Board should (1) exercise our discretion under certain provisions and (2) balance the incentives necessary to encourage rapid deployment of renewable energy generation projects with the obligation to ensure that those incentives are not excessive.

Renewable Energy Vermont ("REV") asserts that this requirement sets out three directives: (1) the price must "guarantee or secure with certainty" that rapid development and commissioning of standard-offer projects will occur; (2) the prices must create an incentive for development and commissioning to occur speedily; and (3) the prices must create an incentive for both development of standard-offer projects and their commissioning. REV further argues that this statutory directive includes no consideration of the provision of least-cost energy services under Section 218c of Title 30. REV observes that the previous version of Section 8005(b)(2) contained reference to least-cost principles, but that the 2009 amendment removed this provision. As a result, REV asserts that the Board should view the policy recommendations of other witnesses, who tried to incorporate least-cost principles, as inconsistent with the statutory directives.

The Department of Public Service ("DPS" or "Department") maintains that the approach towards implementation of Section 8005(b)(2) will lock in rates for years and, to the extent that those rates are in excess of market prices, would lead to millions of dollars of additional expenses for ratepayers. The Department contends that, although the statute bases prices on project costs, the statutory language "does not discard the principles of least-cost planning entirely." As a result, the Department urges caution in setting the prices in this docket, including the adoption of a conservative approach to cost and performance assumptions. Further, the Department asserts that prices should be set based on costs of well-designed systems in favorable locations and the assumption that developers seek to optimize available financial support. The principles enunciated by the Department lead it to oppose setting different rates for smaller-sized projects within each category.

The Department also argues that REV's assertion that the Board must ensure rapid deployment ignores the second part of the statutory mandate specifying that the Board should ensure that incentives do not exceed the level needed. The Department adds that the statute does not mandate that the rapid deployment occur immediately, but actually contemplates continued revision to standard-offer prices over time. Finally, the Department maintains that least-cost planning principles in Section 218c still are relevant, specifically in the manner in which the Board decides to implement the statute.

Central Vermont Public Service Corporation ("CVPS") contends that, in setting standard-offer prices, the Board should make decisions within the least-cost integrated planning framework and, where the statute allows the Board discretion, should favor reducing the risks to ratepayers from excessive costs. This approach, argues CVPS, should mean that prices established by the Board should encourage "the most efficient and cost-effective new renewable resources" within the SPEED program. CVPS notes that, as of now, the standard-offer program is expected to result in Vermont ratepayers incurring added costs in excess of $58 million, thus reinforcing the need to set rates based upon efficient technologies. Finally, CVPS asserts that least-cost principles are, in fact, embodied in the standard-offer program through the mandate to set prices that are not excessive.

Section 8005(b)(2)(B)(i) sets out the following criteria for setting prices under the standard-offer program:

> (I) The board shall determine a generic cost, based on an economic analysis, for each category of generation technology that constitutes renewable energy. In conducting such an economic analysis the board shall: (aa) Include a generic assumption that reflects reasonably available tax credits and other incentives provided by federal and state governments and other sources applicable to the

> category of generation technology. For the purpose of this subdivision (2)(B), the term "tax credits and other incentives" excludes tradeable renewable energy credits. (bb) Consider different generic costs for subcategories of different plant capacities within each category of generation technology.
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> (II) The board shall include a rate of return on equity not less than the highest rate of return on equity received by a Vermont investor-owned retail electric service provider under its board-approved rates as of the date a standard offer goes into effect.
>
> (III) The board shall include such adjustment to the generic costs and rate of return on equity determined under subdivisions (2)(B)(i)(I) and (II) of this subsection as the board determines to be necessary to ensure that the price provides sufficient incentive for the rapid development and commissioning of plants and does not exceed the amount needed to provide such an incentive.

The parties' disagreement on the Board's implementation of the standard-offer program largely rests upon the emphasis each places on the last subsection. For REV, the Board must decide all issues and weigh evidence to ensure rapid deployment. Other parties emphasize the need to make sure the incentives are not excessive.

Section 8005 sets out a mechanism for standard-offer prices that is not founded upon traditional principles of least-cost energy services or reliance upon the market to establish reasonableness and fairness of the prices. Rather, the Legislature has directed the Board to base prices upon the cost of deploying the technology, even if these result in prices in excess of other alternatives in the market. Specifically, the standard-offer price for a technology is derived from (1) the cost of that technology (which includes consideration of not only the installation costs, but also of reasonably expected tax credits and grants), (2) a return on equity, which the statute specifies must be the highest rate of return ("ROE") of any Vermont investor-owned electric company, and (3) an adjustment that provides an appropriate, but not excessive, incentive for rapid deployment. By definition, this mechanism is not designed to produce a least-cost power portfolio, but rather to create a structure that encourages, up to a maximum commissioned amount of 50 MW, development of renewable energy projects, many of which may not be cost-effective. This is readily apparent in Section 8005(b)(2)(B)(i)(III), which authorizes the Board to adjust the cost-based prices to encourage renewable projects, as well as in the goals of the SPEED program enunciated in Section 8001.

At the same time, we do not accept REV's conclusion that the only directive under the statute is to ensure rapid development of renewable resources, irrespective of the cost to Vermont ratepayers. Section 8005(b)(2)(B)(i)(III) does require the Board to adjust the prices we derived based upon the developers' costs to "ensure that the price provides sufficient incentive for the rapid development and commissioning of plants." However, this portion of the statute cannot be read in isolation of other, countervailing, directives set forth in Section 8005.

Significantly, the legislature balances this incentive with other considerations by requiring that the Board adjust the prices so that they do not "exceed the amount needed to provide" an incentive for rapid deployment of renewable energy sources. With a sufficiently high incentive, there is little question that renewable development would occur almost immediately; in fact, the over-subscription to the initial standard-offer prices in October would suggest that this has happened already.

The requirement that the incentive not be in excess of what is needed implicitly recognizes this possibility and makes clear that the statutory goal is not renewable energy development at any price. Prices paid to renewable energy developers that exceed the price of other energy products available on the market have a direct cost to Vermont ratepayers. In this proceeding, the Department has estimated those costs as approximately $58 million, based upon the projects now in the development queue.[13] The larger the incentive the Board establishes for renewable energy developers, the larger the excess costs paid by Vermont ratepayers.

Concern for the cost impact on Vermont consumers is not only consistent with the statutory directive that we ensure that the incentive is not excessive, but also with other principles set out in Vermont law. For example, the SPEED program goals themselves recognize a balancing between rate impacts and renewable energy. Thus, Section 8001(a)(1) states that it is in the interest of the state to promote a state energy policy under Section 202a by:

> Balancing the benefits, lifetime costs, and rates of the state's overall energy portfolio to ensure that to the greatest extent possible the economic benefits of renewable energy in the state flow to the Vermont economy in general, and to the rate paying citizens of the state in particular.

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13. Tr. 12/3/09 at 176–177 (Nagle).

Moreover, the specific reference in Section 8001(a) to the SPEED program goals as promoting state energy policy reflects an intent to augment, not supplant those policies. Section 202a defines the policies as:

> (1) To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality, the efficient use of energy resources and cost effective demand side management; and that is environmentally sound.
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> (2) To identify and evaluate on an ongoing basis, resources that will meet Vermont's energy service needs in accordance with the principles of least cost integrated planning; including efficiency, conservation and load management alternatives, wise use of renewable resources and environmentally sound energy supply.

These references make clear that, although we agree with REV that the statute does not require that prices set under the standard-offer program be constrained by least-cost principles, the statute does require the Board to consider these principles in the Board's exercise of judgment. Accordingly, our recommendations to the Board on the appropriate adjustment factor to ensure that the incentive is enough, but not too much, are guided by these considerations of the broader state energy policy and SPEED program goals. This also affects the manner in which we recommend the Board weigh evidence on other aspects of decision-making under Section 8005(b)(2). For example, the Board must determine the appropriate costs to use, which includes not only direct installation costs, but also financing, interconnection, and operations and maintenance, and what assumptions to make about performance. Further, the Board must consider what tax credits or other incentives for renewable technology are reasonable to assume and, under subdivision (b)(2)(B)(i)(I)(bb), whether it is appropriate to establish different standard-offer prices for different plant capacities within each category of renewable generation technology specified by the statute.

Balancing the statutory directive to ensure sufficient incentive for rapid deployment of renewables against our duty to ensure that the incentive is not excessive, and thereby unnecessarily costly for ratepayers, we recommend that the Board set standard-offer prices based upon the assumption that the projects being developed are reasonably efficient. This means that they use efficient renewable energy technology, are favorably sited (from both the standpoint of optimizing output and minimizing transmission costs), and take advantage of economies of scale. To do otherwise would cause Vermont consumers to pay excessive electricity costs; moreover, it would provide an unnecessarily large incentive to renewable projects that are more efficient and favorably located. Such excess payments would contravene the statutory requirement that the incentive not be in excess of what was needed.

Our consideration of the appropriate incentive level is also informed by the fact that the statutory scheme itself builds in a large return for developers. The statute requires that the Board assume a return on equity equal to the highest for any investor-owned utility in the state. As the Board stated in its September 15, 2009, Order in Docket 7523, that return was established in 1990. At that time, the 12.125% return for Vermont Marble was generally consistent with (and, in fact, lower than) returns for other investor-owned utilities.[14] Since that time, returns for these other companies have dropped below 10%; due to the special circumstances of Vermont Marble, the Board has not adjusted its return.[15] The current returns for the state's largest investor-owned utilities strongly indicates that the 12.125% return is higher than necessary to attract capital. Thus, its inclusion in the cost assumptions already provides an incentive to the renewable project developers, that is greater than the level an investor-owned utility would expect. Adding further incentives, or basing standard-offer prices on assumptions other than those associated with efficient projects, would exacerbate the degree to which the return and, therefore the incentive, is excessive.

These considerations lead us to recommend that the Board employ a conservative approach to evaluating the cost assumptions in this proceeding. This Proposal for Decision reflects that approach.

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14. For example, in Docket 5428, the Board found that a 12.5% return on equity for Green Mountain Power Corporation was reasonable. Order of 1/4/91 at 88.

15. Authorized returns on equity for Green Mountain Power Corporation ("GMP") and Central Vermont Public Service Corporation ("CVPS") are now less than 10%. Since 1990, Vermont Marble has not petitioned the Board for a change to its rates, nor has the Department advocated an investigation into Vermont Marble's rates, until Vermont Marble filed a petition for a rate increase on January 6, 2010.

B. Experience to Date with Applications for Standard Offer Prices

Findings

4. The Board opened the queue for renewable projects to seek contracts with standard-offer prices on October 19, 2009. In establishing the queue, the Board set a cap of 12.5 MW for any single technology. Order of 9/30/09.

5. The queue filled almost immediately. As of October 30, 2009, the SPEED Facilitator had accepted enough projects to reach the 50 MW cap for the program. The technologies for the projects that applied included all categories set out in the statute: solar, wind, farm methane, landfill methane, hydroelectric, and biomass. Exh. Board-3.

6. The projects that were accepted ranged in size from 2 kW to 2.2 MW (although the 2 kW project has since withdrawn so that the smallest proposed facility is 26 kW). Exh. Board-3.

7. Applications for the biomass and solar categories exceeded the 12.5 MW technology sub-cap specified by the Board, with solar applications exceeding the subcap by more than 10 times. Exhs. Board-3–7.

8. A number of the projects that have applied to date are less likely to be constructed and commissioned. Tr. 12/4/09 at 60–65 (Spencer).

Discussion

On September 15, 2009, the Board issued an Order setting standard-offer prices. The Order accepted the statutory default prices for most categories, although the farm methane rate was increased. In a September 30 Order, the Board directed that the Speed Facilitator begin accepting applications under the program on October 19.

On that date, applications filled the subcap for the biomass and solar categories, with the solar category receiving applications totaling more than 10 times the subcap and far exceeding the total 50 MW ceiling. Within a few days, the entire 50 MW standard-offer program was filled, with applications in each category of renewable energy generation.

The receipt of applications for over 180 MW of renewable generation suggests that those applicants found the standard-offer price attractive. We recognize that a number of these projects will not be completed or will be withdrawn. And the current interest level does not demonstrate that the projects will all be commissioned. However, with the substantial excess of capacity, even if a large number of projects are not completed, the program is likely to meet the 50 MW cap within a short period of time. The experience of the first offering under the standard-offer program indicates that the incentives built into the prices were sufficient to encourage rapid development of renewable resources and may have been greater than necessary to achieve such development. We recommend that the Board take this into account when assessing the reasonableness of cost assumptions and the appropriate adjustments to the prices.

C. Establishment of Separate Categories

Findings

9. Different prices within each category allows a wider range of project types and technologies to participate in a standard-offer program. Dalton pf. reb. at 27.

10. Economies of scale exist in renewable electricity generation so that smaller projects generally have higher costs. Dalton pf. reb. at 27.

11. Developers of smaller projects are more likely owned by the host and more willing to accept a lower return. Dalton pf. reb. at 27; tr. 12/4/09 at 115–116, 122 (Dalton).

12. The composition of proposed projects that submitted applications for contracts indicates that the standard-offer program has achieved a reasonable level of granularity. Dalton pf. reb. at 27; Lamont pf. at 6; exh. Board-3.

Discussion

Section 8005(b)(2)(B)(i)(I)(bb) directs the Board to consider whether to establish different standard-offer prices for different plant capacities within each category of renewable generation. The statutory default prices set a single price for each category, except for the establishment of a separate category for wind generation facilities of 15 kW capacity or less.

REV argues that the Board must set a price for a category of generation technology if facts support that it is fundamental or distinct. In particular, REV argues that the Board must set a separate category for wind projects under 100 kW and for biomass facilities that use wood biomass as a fuel source.[16] The Department opposes separate prices within categories because such price differentiation could increase costs for ratepayers, since renewable energy could be purchased for less from larger or more efficient sources.

We recommend that the Board find that there is no need for further subdivision of categories at the present time. As this PFD explains above, to ensure that prices and incentives are not excessive, we propose that the prices be based upon the assumption of efficiently sized and located generation facilities. Disaggregation of categories, with higher prices for smaller units, is inconsistent with this principle as it requires ratepayers to pay more without acquiring more renewable energy. Moreover, the evidence points to the conclusion that, although certain prices for smaller facilities may be higher, the expected return for such projects may be lower.

The experience of the standard-offer program to date also would suggest that further price differentiation is unnecessary. The initial prices from September 2009 did not differentiate based upon size. Yet the projects now within the 50 MW cap range in size from small, 26 kW solar facilities to 2.2 MW projects. The waiting list of projects include proposed generation facilities as small as 2 kW. The absence of different prices within categories has not served as an impediment to applicants of all sizes.

Finally, we do not accept REV's interpretation of the statute as requiring that we establish subcategories. Section 8005(b)(2) does not explicitly require such subcategorization. Instead, it directs the Board to "consider" whether to establish subcategories. This is not mandatory. In this PFD, we recommend that the Board find that no party has demonstrated the need to establish further subcategories of prices.

IV. Issues of General Applications

A. Model Designation

Findings

16. REV Brief at 4–7.

13. The spreadsheet cost models used in modeling generic costs for the September 15, 2009, determinations in Docket 7523 were used as the basis for initial discussions around the development of a generic cost model for the January 15, 2010, determinations. Dalton pf. reb. at 5.

14. Mr. Dalton created opportunities for modifications to the model. Mr. Dalton solicited comments through e-mail to the participants, and held a workshop on November 5, 2009. Changes to the model followed comments from the Department's John Becker and REV's Mr. Matthew Karcher. Dalton pf. reb. at 4.

15. The Board's Independent Witness enumerated nine structural changes to the models that were used in the September 15, 2009, determinations. Dalton pf. reb. at 4-5.

16. Mr. Dalton ran the REV assumptions in his model, and came up with a price within 2 cents per MWh as compared with his own model runs. Tr. 12/4/09 at 105-106 (Dalton).

17. Mr. Dalton distributed the updated models that have been agreed to by the parties through the group e-mail list on December 29, 2009. (E-mail communications from John Dalton, 12/29/09).

Discussion

The DPS, REV and the Independent Board witness, who have each been the active parties to this proceeding on the modeling issues, agreed to the structure of the costing model and many of the assumptions pertaining to the modeling of these technology categories.[17] Consensus spreadsheet cost models were initially developed in the context of the Docket 7523 interim price determinations. These models were refined in the current proceeding by various experts representing the Department, REV, and the Board's Independent Witness.[18] The Board's Independent Witness coordinated a number of changes to the model in the course of developing written testimony. Further suggested changes were also provided by REV's witnesses in testimony. By the conclusion of the technical hearings, it was clear that the functioning of the

17. REV Brief at 7.

18. The Board's Independent Witness had served as an independent consultant during the proceedings leading to the September 15 price determinations and had assisted with the development of the model at that time.

models were actually quite similar and, as such, there was little material differences between the parties that had bearing on the price determinations.

At the encouragement of the Hearing Officers, the active participants engaged in the development of the model were encouraged to reconcile any residual differences between the models. Reconciling such differences facilitates final price determinations once the issues surrounding the input assumptions have been resolved (i.e., differences over the modeling inputs have been resolved through Board determinations). The Board's Independent Witness facilitated the final stages of model development and represented on December 29, 2009, that agreement had been reached on the five basic models for the Standard Offer pricing analysis by the Board's Independent Witness, REV and the Department. The model was then posted on the Board's web site. No other parties raised concerns with the model.

At this stage, we know of no remaining issues related to the financial spreadsheet model that will be used to make the final price analysis. Based on the extensive work and analysis that lead to the development of this model, together with the agreement that has been reached among the participants and their respective modeling experts, we approve the models that were provided by Mr. Dalton. The models will be posted to the Board's web site along with the input assumptions used by the Board's independent witness to facilitate review of the work of the independent witness in establishing prices in compliance with this proposed decision.

B. Inflation Rate

Findings

18. REV and GMP assume an inflation rate of 2.5%; the DPS assumes 1.5%; and Mr. Dalton assumes 1.6%. Exh. REV-WR/MK-6; Becker pf. at 2; Gifford pf. at 9; Dalton pf. reb. at 23.

19. With all other assumptions held constant, varying the rate of inflation assumption from 1.5% to 2.5% does not have a significant impact on the resulting prices established by the model. An inflation rate of anywhere between 1.5% and 2.5% is reasonable. Tr. 12/4/09 at 23-24 (Karcher).

20. There are two primary alternative indices of prices that could be used to measure the impact of inflation on the operating and maintenance costs of the eligible standard offer generating technologies. These alternatives are the Consumer Price Index ("CPI"), which is the most widely known and used index, and the implicit Gross Domestic Product ("GPD") deflator, which is the difference between the GDP in nominal (current) dollars and the GDP in real (constant) dollars. The CPI is essentially a cost-of-living index and is not necessarily an appropriate index for measuring the increases in the costs of operating and maintaining a renewable generating facility. Dalton pf. reb. at 21.

21. The GDP implicit price deflator measures the average increase in prices for all goods and services in the economy, unlike the CPI, which is based on a fixed basket of goods. The implicit GDP deflator is a broader measure of inflation which allows for the substitution of cost inputs. It reflects elements of cost, such as the cost of purchased materials or equipment that are not in the CPI. Dalton pf. reb. at 22.

22. The inflation rate recommended by the Department is calculated using the implicit GDP deflator. Dalton pf. reb. at 22.

23. Economy.com predicts that for the period from 2009 – 2027, there will be a lower inflation rate than historically has been the case and forecasts a rate of 1.5%. Lamont pf. at 4.

24. The Energy Information Administration of the US Department of Energy publishes an annual long-term energy outlook. In the assumptions to its latest (March 2009) publication, it uses as its reference case a compound annual growth rate from 2007 to 2030 of 1.6% for a "GDP Chain-type price index," which is essentially the implicit GDP deflator. Dalton pf. at 22.

25. Inflation measured by the CPI tends to be higher than the Implicit GDP deflator by about 0.6% over the last 20 to 40 years. Dalton pf. reb. at 23.

26. The Consensus Forecast for CPI supports an implicit GDP deflator forecast of 1.6%. Dalton pf. reb at 23.

27. The cost models used for the analysis need to reflect an appropriate inflation factor for the operating and maintenance expenses included in the model. Dalton, pf. reb. at 21-22.

Discussion

The cost models used in the analysis rely on a generalized measure of inflation to capture nominal price escalation associated with the various components of costs, particularly operating and maintenance expenses. The testimony in this proceeding suggests that the inflation rate used as an input to the modeling is not likely to have a material impact on the resulting price determinations. Nevertheless, the precise value remains unresolved and requires a determination by the Board.

Based on the testimony from REV's experts, a range of values between 1.5 and 2.5 % may be appropriately relied upon for modeling prices. The considerable range may be due, in part, by differences between the measures used to gauge inflation. Mr. Dalton is persuasive in recommending the implicit GDP deflator or GDP price deflator, as the appropriate measure for application in the models. The GPD price deflator is typically below that of the CPI by about 0.6% and is more likely to measure cost affect of inflation than the more generalized CPI. The Department's estimate of 1.5% falls within the range of a reasonable estimate identified by REV's expert. The estimate provided by Mr. Dalton of 1.6 % is also very close to that relied on by the Department and is based on two sources.

As the Department notes, in its brief, its estimates were provided by a reliable and well established forecasting firm. We conclude that either a value of 1.5 or 1.6 % is reasonable and, based on the scope of analysis performed by Mr. Dalton, recommend that 1.6% be used for purposes of the price determinations in all areas of the model that rely on a general measure of nominal price inflation.

C. Standard Offer Price Escalation for Inflation

Findings

28. Recent updates to the model by the Board's Independent Witness allow the model to provide for a portion of the contract price to escalate by inflation. Dalton pf. reb. at 23.

29. The objective of allowing the portion of the contract price to escalate by inflation is to mitigate the risk to project owners of changes in the rate of inflation. Dalton pf. reb. at 23.

30. Ontario's standard offer and feed-in tariff program allowed 20% of the contract price to escalate by inflation. Dalton pf. reb. at 24.

31. The stability of debt service coverage ratios and how often cash flows become negative provides an indication of the appropriate portion of the contract price that should escalate by inflation. Dalton pf. reb. at 24.

32. The proportion of the contract price that would escalate should approximate the proportion of the project costs that would escalate with inflation. The stability of debt service coverage rations and the likelihood of negative cash flows also informs the decision on the appropriate portion of the contract price that should escalate. Dalton pf. reb. at 24.

33. Based on the modeling, it is reasonable that 30% of the contract price should escalate with inflation. Establishing one percentage across multiple technologies provides for administrative simplicity. Dalton pf. reb. at 24.

34. Only a very small portion of costs for solar PV projects escalate with inflation. Therefore, solar PV project standard offer prices should be set at a flat rate. Dalton pf. reb. at 24.

35. Establishing some form of inflationary adjustment as a component of price escalation will help to mitigate concerns associated with a negative cash flow in some years. Tr. 12/4/09 at 45 (Karcher).

36. From a financing perspective, it would be better to establish the price escalation factor in advance, rather than allow it to vary year-to-year by some index. Tr. 12/4/09 at 45-46 (Karcher).

Discussion

The September 15, 2009 price determinations were set at a flat nominal rate, largely based on the statutory default prices. Such nominal prices introduce risks to plant owners, to the extent that underlying costs vary considerably from the prices paid at any given time. Additionally, ratepayers in any one timeframe may bear more than a reasonable share of the project costs since payments to developers are front-loaded. In either event, we can reduce the risk that price determinations do not vary from underlying cost changes by incorporating an inflation adjustment in the price determinations that are made.

Mr. Dalton recommends that a portion of the contract price escalate with inflation for all technologies except for solar PV projects, as the costs of this technolgy are expected to vary little with inflation. This assumption relates to projects that have significant operating and maintenance expense ("O&M"), so that it would not apply to solar PV projects.[19] The Department supports this approach.[20] The Department also supports reliance on the GDP deflator as the appropriate index.[21] REV also finds the proposal to be reasonable, although REV recommends that, to facilitate project financing and reduce risk, the Board should fix the inflation rate at the present time.[22]

We recommend that the Board accept Mr. Dalton's proposal. The standard-offer prices should be established so that 30% of the price will escalate with inflation.[23] This adjustment does not apply to solar PV projects, which are expected to vary little with inflation. We also recommend that the Board fix the inflation rate at the present time, using the 1.6% rate that we find appropriate above. This is different from the Board's Independent Witness' proposal, which would use the actual inflation rate at the time, thereby helping developers manage their risk.[24] We reach this conclusion largely in reliance upon the testimony from the developers that specifying the price escalation factor now will aid in project financing. For solar, we recommend that prices be set at a flat nominal amount over the 25-year term of the standard offer contract.

D. Debt Service Reserve

Findings

37. Non-recourse project financing is a financial structure that is attractive to developers because it can allow for significant leverage of lower cost debt in a manner that does not affect the borrowing capacity of the developer. Under such arrangements, debt is secured by the project assets with lenders evaluating projected cash flows to ensure that they are likely to be sufficient to

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19. Tr. 12/4/09 at 112 (Dalton).

20. DPS Brief at 22.

21. DPS Brief at 9 and 22.

22. Tr. 12/4/09 at 45–46 (Karcher).

23. Price escalation does not result in an increase in the total expected revenue for project developers. Rather, it would restructure the timing of the payments under the standard-offer program.

24. Tr. 12/4/09 at 113 (Dalton).

cover debt service payments and operating expenses. To cover unforeseen contingencies, cash reserves typically are required to be held in escrow to cover debt service payments and operating expenses. Dalton pf. reb. at 11.

38. Project financing and tax equity financing are most suited to relatively large projects. Smaller projects are more likely to use more conventional financing sources with debt issued based on the credit of the host facility (e.g., a big box store) or a more conventional form of collateral (for example, we assume that, for farm methane projects, real estate will serve as collateral). Debt issued under such transactions typically is an obligation of the borrower (i.e., recourse). Such projects typically do not require the same amount of project-related due diligence, given that the focus of the lender is on the ability of the plant owner to pay back the loan, rather than the project generating sufficient cash flow to repay the loan. This reduces the cost and effort required to secure such loans. Dalton pf. reb. at 12.

39. The debt issued based on the credit of the host facility or on more conventional collateral, typically is an obligation of the borrower (i.e., recourse) and as such is required by accounting and financial reporting rules to be identified as a financial obligation on its financial statements. The primary advantage of this approach is that lenders typically do not require the same amount of project-related due diligence given that the focus is on the ability of the project sponsor to pay back the loan rather than ensure that the project generates sufficient cash flow to repay the loan. Dalton pf. reb. at 12.

40. The debt issued based on the credit of the host facility, or on more conventional collateral reduces the cost and effort required to secure such loans. However, plant owners with poor or limited credit will have a harder time securing such loans or will only be able to do so on less favorable terms. Dalton pf. reb. at 12.

41. It is typical for project financing models to include up-front funding, treated as a capitalized cost for a debt service reserve. Rickerson/Karcher pf. at 4; Dalton pf. reb at 11.

42. For this assumption, REV, the DPS and Mr. Dalton assumed 6 months of debt service; GMP assumed 4.5 months. Rickerson/Karcher pf. reb. at 12; Dalton pf. reb. at 35; Gifford pf. at 9; Becker pf. at 5.

43. Only a limited number of projects participating in the standard offer program will likely use a formal project finance approach where there is a high degree of leverage and the debt is non-resource. Dalton pf. reb. at 13.

44. Large solar PV projects would likely employ a project finance structure and include debt service and maintenance reserves in the cash flow model. Dalton pf. reb. at 13-14.

45. Smaller projects will likely be financed using more conventional loans, which are not likely to require cash reserves for debt service or operating expense. Dalton pf. reb. at 14.

46. A project-financed approach requires debt service reserves and maintenance and operating expense reserves. Products using this approach would need to satisfy average debt-service coverage ratios of 1.5 and minimum debt-service coverage ratios of 1.2. Dalton pf. reb. at 14.

47. The inclusion of a debt-service reserve had a slight impact on the results of the modeling. Rickerson/Karcher pf. reb. at 4.

48. In the last six months, the interest rate on long-term BAA bonds, which are indicative of terms that could be available for the most financially-sound larger generation projects, have declined by almost 175 basis points. This provides an indication of the type of windfall to developers that could result in using assumptions specific to the current financial market if financial market conditions continue to improve. Dalton pf. reb. at 15.

49. Financial market conditions appear likely to improve based on the difference in spreads between corporate bond interest rates and government bond interest rates. Between 2004 and 2006, the average spread between 20-year Government Bonds and BAA-rated corporate bonds was 140 basis points. The differences have narrowed in recent months, but the average equivalent credit spread in October 2009 was over 210 basis points, or 50% higher than the average spread in recent years. Dalton pf. reb. at 16-17.

50. It is appropriate to take a prospective view of future financial market conditions when establishing the assumptions for financing these standard-offer projects. Dalton pf. at 17.

51. The ultimate buyers for the power are the Vermont distribution utilities. There is not a single counterparty. This fact should reduce the perceived credit risks to the seller. As such, the standard-offer contract will not be viewed as unduly risky by lenders. Dalton pf. reb. at 18.

52. The assumption that financial market conditions continue to improve represents a reasonable risk for project developers to bear and manage. Dalton pf. reb. at 15.

53. In the case of solar PV project developers, risks are mitigated by the fact that their security deposit is not at risk for the first 12 months after contract execution. Solar PV project developers appear to be willing to take risks associated with the continued decline in the cost of PV modules and can be expected to accept similar risk regarding the continued improvement in credit market conditions. Dalton pf. reb. at 16.

Discussion

The debt reserve was originally omitted in modeling runs. Based on the testimony, it appears that including the debt reserve in the modeling has only a modest impact on the results.[25] There is general agreement that a debt service reserve, treated as a capitalized cost, should be included in the modeling of the costs for larger projects that are project financed.

We agree with the Board's Independent Witness that the majority of the projects will not receive project financing, but will receive loans with some recourse to assets or income of the borrower. Large solar projects represent an exception. Assumptions related to reserve accounts and financing should reflect this distinction.

The Board's Independent Witness included this assumption in his later model for solar projects, which he assumed were based on a project-financed arrangement. There is a slight difference between the GMP assumptions regarding debt reserve for solar projects and those used by the other experts. On balance, we conclude that a six-month debt reserve based on interest and principle payments is appropriate and therefore recommend that it be included in the modeling of

25. Based on the analysis of Mr. Rickerson and Mr. Karcher, the inclusion of a six-month reserve, in isolation of other factors, increased the required price for one technology from \$119/Mwh to \$123/Mwh. While such a difference, in isolation, may have little material impact in the resulting prices (the resulting prices may round to the same value regardless of whether the six-month reserve is included), with the addition of other assumptions omitted from the prior model, they can contribute to a material change in the results.

large solar energy projects that are the most likely to receive project financing.[26] No such reserve is required for other categories based on differences between the source of debt.

E. Working Capital and Maintenance Reserves

Findings

54. Working capital should generally include three months of operating and maintenance expenses, except for farms, which should be one-and-a-half months. Dalton pf. reb. at 28; exh. Board-JCD-7.

55. GMP's solar expert recommends that the working capital be comprised of 6 months of O&M. GMP assumed no separate reserve for maintenance, independent of working capital. Gifford pf. at 9; exh. GMP-26.

56. Generally, the working capital reserve account would include all operating costs and be sized to include 3 to 6 months. Rickerson/Karcher pf. at 7.

57. An operating reserve account established to reflect required cash reserves for O&M expenses is typical of project financing structures. Dalton pf. reb. at 13-14.

58. Only a limited number of projects participating in the standard offer program will use a formal project finance approach where there is a high degree of leverage and the debt is non-recourse. Dalton pf. reb. at 13.

59. It is reasonable for projects that employ a project finance structure to include debt service and maintenance reserves in the cash flow model for these projects. Dalton pf. reb. at 13.

Discussion

The topic of working capital received little attention in the testimony and briefs. The sensitivity analysis of Mr. Rickerson and Mr. Karcher suggests that the addition of working capital in the model would result in little material impact. (Rickerson/Karcher pf. at 7-8). The

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26. By "large" here, we refer only to the larger projects that were modeled under the SPEED standard offer program. Specifically, we are referring to 2.2 MW solar projects. While small solar projects are not modeled separately, such a debt reserve is, for purposes of the modeling, assumed to be unnecessary due to the nature of the underlying debt instrument and the differential requirements of the financial institutions that are the source of such debt.

testimony regarding the assumptions for working capital appears reasonable, and generally assume 3 to 6 months of operating reserves. We recommend that the assumed project financed large solar project include a combined maintenance and working capital allowance equal to 6 months of O&M.

For other categories, we recommend only a single working capital reserve account equal to 3 months of O&M apply across all resource categories except farms, reflecting fewer demands of lenders associated with projects that are financed through loans that are not project financed.

Farm methane projects should include only a one-and-a-half month reserve allowance for annual expenses, including salaries, for working capital reserve.

We recommend including all operating costs, including insurance and property taxes, in line with the recommendations of REV. The Department relied on similar assumptions in its calculation of the Working Capital reserve. (Exh. DPS-4, Spreadsheet models for wind and solar).

F. Debt Tenor (Debt Tail and Mini-Perm Loans)

Findings

60. For initial modeling purposes, REV and Mr. Dalton used an 18-year debt term; the DPS recommended using a 25-year debt term; and GMP assumed a 20-year debt term. Rickerson/Karcher pf. reb. at 2-3; Dalton pf. reb. at 21; Becker pf. at 13; tr. 12/4/09 at 90 (Dalton); Gifford pf. at 9.

61. The London Inter-Bank Offer Rate ("LIBOR") is the rate at which banks lend to each other set on a daily basis that is variable. Parties can secure a fixed rate using an interest rate swap. A review of recent debt transactions indicates that pricing for mini-perm loans[27] ranges from 300 to 325 basis points above the LIBOR. The current LIBOR rate is 1.09 %. Dalton pf. reb. at 18-19.

62. The addition of 258 basis points for a five-year interest rate swap yields an effective interest rate of 6.82%. Dalton pf. reb. at 19.

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27. Mini-perm loans are loans with typically a shorter repayment term (e.g., 7-10 years) and a longer underlying amortization schedule (e.g, 15-18 years). Rickerson/Karcher pf. at 10.

63. It is reasonable to expect further declines in interest rates. Bankers expect to see a drop in debt pricing and an extension in loan tenors, with the LIBOR premium dropping. Dalton pf. reb. at 19.

64. A mini-perm is a loan that needs to be repaid after the end of 5-7 years, but the loan payment amount is amortized as if the loan was longer. Tr. 12/4/09 at 15-17 (Karcher).

65. A rate of 7.5 % is 70 basis points above the likely pricing for a mini-perm loan and provides a margin for uncertainty regarding the types of loans that will ultimately be utilized to cover financing costs. Dalton pf. reb. at 19.

66. The Vermont Economic Development Authority ("VEDA") and the Clean Economic Development Fund ("CEDF") can lower the effective cost of borrowing for these projects and temper the risk of higher interest rates. Dalton pf. reb. at 19-20.

67. Standard Offer projects could receive a CEDF loan, but only under extraordinary circumstances. Exh. Board-7.

68. Due to the collapse of the credit markets, commercial banks are generally only offering mini-perm loans at this time. Tr. 12/4/09 at 15-17 (Karcher).

69. It is typical for financing for renewable energy projects to have a "loan tail," the period extending from when the debt term is complete and when the power purchase agreement terminates. Tr. 12/2/09 at 89-90 (Gifford).

70. The lower risk nature of these projects due to the long-term fixed price contracts that are backed by legislation and approved by a Board Order, coupled with the long design life of the projects, should lead to more favorable loan terms compared to a conventional project. Becker pf. at 4-5.

71. The ultimate buyer for the power from these projects is the Vermont distribution utilities. There will not be a single counterparty. Accordingly, perceived credit risk should be low. Dalton pf. reb. at 18.

72. A reasonable debt term for small wind and farm is 10 years. Exh. Board-JCD-7.

Discussion

The debt "tenor," or term of the loan, is relevant to these proceedings because shorter debt terms may necessitate refinancing of loans with the attendant costs of re-financing that should be included in the modeling. In its brief, the Department ranked this issue as "middle" in importance among the issues under consideration.

For its part, the Department has simply recommended that the loan term match the length of the long-term fixed price contract. These contracts represent new arrangements and they argue that we should look at analogous situations to gain insights into how the financial community will respond. Long-term contracts are viewed favorably by developers. The Department argues that potential lenders will also respond favorably to the relatively secure nature of the contract and its lower risks and structure the length of the debt instrument accordingly. The Department further states that, to the extent that refinancing is required of projects, then such refinancing will simply occur in a manner consistent with the current independent power contracts established under Board Rule 4.100.

The models developed by REV, the Board's Independent Witness, and GMP all included a "loan tail," the period from when the debt term is complete and when the power purchase agreement terminates. And indeed, the evidence indicates that under the current market conditions, commercial banks are generally only offering "mini-perm" loans, due to the recent collapse of credit markets.

In general, we conclude that, given the current market conditions, it is inappropriate to assume that developers will be able to find arrangements where the term of the loan or debt tenor will match the term of the contract. The Department is correct that these should be viewed by the lenders as relatively low-risk arrangements, and they may be correct that the financial community may respond to these long-term contracts with more favorable terms and longer term loan instruments, but it seems premature to simply assume that this will occur in the current environment or the immediate future.

We recommend that the debt tenor include a tail, consistent with current market realities. That said, the testimony generally supports a view that conditions are improving and that most projects should find loans that are consistent with the longer term nature of the assets and the term of the contracts. For purposes of the modeling we recommend that the Board adopt the loan amortization periods set forth below. These correspond to the actual debt tenors in all instances except for large solar where we recommend that a mini-perm structure apply to the first portion of the contract term and be replaced later by a loan that covers the remainder of the loan amortization period. The practical difference, in terms of the modeling, is that additional costs are incurred in the seventh year due to the need to refinance. The refinancing cost would equal 3% of the unamortized cost of the loan.[28]

Large Solar – 18 Years

Large Wind – 18 Years

Small Wind (15 kW) – 10 Years

Hydro – 18 Years

Landfill Methane – 13 Years on 15-Year Contract Prices

Farm Methane – 10 Years

Given the earlier discussion concerning the increased likelihood that large solar projects will be project financed, as well as the current lending practices that favor mini-perm loans, we direct the Board's Independent Witness to amortize the loans as described above, but also include in the modeling the additional costs of financing associated with solar projects due to the nature of the financing.

G. Interest Rates/Cost of Debt

Findings

73. GMP and the DPS assume an interest rate of 7%. Mr. Dalton and REV assume an interest rate of 7.5%. Rickerson/Karcher pf. reb. at 6, 9, 11; Dalton pf. reb. at 19; Gifford pf. at 9; Becker pf. at 5.

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28. Note that we do not recommend including the full amount of the financing cost proposed by REV's experts. We have not included the $50,000 "financing transaction costs." It seems likely that other factors may serve to mitigate the transactions cost of these projects or the closing fee on debt. These factors include alternative forms of financing including recourse loans. Even when project financing was included by the Board's Independent Witness, no additional allowance was made for a 3% closing fee on debt, an estimated $50,000 in financing transaction costs. (Exh. Board-JCD-7.)

74. The interest rates assumed in the modeling ranged from 5.5 % for recourse mortgage-like loans to 7.5% for standard commercial loans. Exh. Board-JCD-7.

75. Another possible source of debt which can lower the effective cost of borrowing for these projects are loans from VEDA and CEDF. These may temper the risk of higher interest rates. Dalton pf. reb. at 19-20.

76. VEDA's current rate for its Direct Loan Program is a 2.75% variable rate. However, these VEDA rates are lower than a typical commercial bank and VEDA does not usually take a full position in any project. Accordingly, a VEDA loan would need to be combined with another commercial bank loan to fund a project. Becker pf. at 5.

77. Vermont utilities recently have been securing financing at around the 7% interest range. Becker pf. at 5.

78. Commercial mortgage loans are currently in the 6% to 7% range. Becker pf. at 5.

79. Based on an analysis of financial markets and interbank lending rates, 6.82% is a high level estimate of the interest rates that are likely to be secured by standard-offer projects that use a mini-perm loan. Dalton pf. reb. at 19.

80. Taking a weighted average of a number of possible loan-type interest rates, leads to an interest rate of approximately 7% with the exception of farm methane projects, for which a 5.5% interest rate would be reasonable. Becker pf. at 6.

81. Recent trade press articles regarding the Boralex project[29] reported a 6.4% interest rate. Tr. 12/4/09 at 111-12 (Dalton).

82. A rate of 6% is recommended for small 15 kW wind projects. Exh. Board-JCD-7.

83. Unless the interest rate is doubled, the impact on the price from the interest rate is not dramatic. Raising interest rates from 7% to 8% in the model makes very little difference in price. Tr. 12/3/09 at 33 (Becker).

29. Boralex is a Canadian-based developer who financed several wind projects in early September with an aggregate capacity of 40 MW. Boralex was able to secure a 5-year loan that will be amortized over 19 years at a rate of 6.4%. Dalton pf. reb. at 18.

<u>Discussion</u>

The participants to this proceeding are in disagreement regarding the correct assumption for interest rates or debt costs (at least "financing costs"). Changes to this assumption in the model makes very little difference in price, at least within the range of assumptions put forward in testimony. Estimates of interest rates range from a low of 5.5% for farm methane projects, which may be financed through some sort of "recourse" loan such as a mortgage, to a high of 7.5%, including commercial loans without recourse to other property or holdings of the entity seeking the financing.

Given the range of estimates provided, we conclude that the appropriate interest rate for unsecured loans is in the range of 7% to 7.5% for all loans other than those for farm methane projects and small projects such as 15 kW wind projects. In the case of these categories, we recommend that the Board adopt the assumptions of 5.5% for farm methane and 6% for small wind. For purposes of the modeling, we recommend a higher rate apply to commercial for the larger projects modeled (above the 15 kW wind). We recommend a midpoint rate of 7.25% be used as a reasonable basis for modeling.

<u>H. Financing Costs and Interest During Construction ("IDC")</u>

<u>Findings</u>

84. For financing costs, REV's experts assumed 3% of the approximate debt amount plus $50 thousand. Exhs. REV-MR-MK-5.1 and REV-MR-MK-6.

85. The Department and the Board's Independent Witness included no additional costs for financing and Interest During Construction ("IDC"). Exh. Board-JCD-7.

86. For project financing, debt is secured by the project assets, with lenders evaluating projected cash flows to ensure that they are likely to be sufficient to cover debt service payments and operating expenses. There are significant fixed costs for project finance deals. This limits their application to projects with significant capital requirements. Dalton pf. reb. at 11.

87. IDC is meant to capture the interest accrued during the construction period, assuming the project is able to secure full financing during construction. Financing is meant to capture

transactional costs associated with securing the long-term project debt. Rickerson/Karcher pf. at 25.

88. For IDC, REV's experts assumed a monthly interest rate of 5/12% and an average construction period (half of the term of the construction) of 4.5 months for large solar and 2 months for large wind. Exhs. REV-MR-MK-5.1 and REV-MR-MK-6.

89. Smaller projects are more likely to be funded by means other than project financing. This may include an entity that was installing a project at an existing business where the value of the real estate could be used to finance the project. Tr. 12/3/09 (Becker).

90. Projects participating in the standard offer program are unlikely to be of a size large enough to cost-effectively utilize tax equity partnerships[30] and project financing structures. Dalton pf. reb. at 11.

Discussion

There was a wide range of assumptions related to project financing and IDC. The Department's witness and the Board's Independent Witness assumed that there would be no additional costs associated with financings and IDC. The exception was for solar projects where the Board's Independent Witness recommended project financing, and with it some additional cost elements.

REV's experts included components of costs for both financing (3% of estimated debt, plus $50,000) and the interest during construction at a 5% annual rate times half the construction period. The latter would seem to have relevance for any project with a substantial construction period. The application of the former would seem to vary by project and the source of funds, and is probably most relevant to project financings.

For projects with lengthy construction periods, we recommend that a provision be made for the costs of the interest during construction. For wind projects we recommend that the amount be set at 5/12% (0.417%) times the average construction period of 4.5 months for solar and

30. Tax equity structures or partnerships involve the utilization of the tax benefits they generate by entering into a partnership with an entity that has a tax "appetite" (i.e., taxable income). Dalton pf. reb. at 10.

2 months for wind times the installed costs of the project.[31] The record is inadequate to establish the construction periods for other projects and we do not recommend that they be included.

In general, we are not persuaded that project financing structures will predominate for standard offer projects. The source of loans will likely vary by project and there any many potential sources. The Board Independent Witness has recommended that project financings be used to model prices for solar PV only. Consistent with this, we recommend that an additional cost component equal to 3% of the approximate debt be used as the basis to the cost of financing large solar installations based on a 3% closing fee on debt.[32] This cost will apply to the approximate debt during the initial loan and again when the project is refinanced in the 7th year after the conclusion of the initial mini-perm loan. Based on the record, we recommend that no additional costs for financing debt apply to the other resource categories.

I. Clean Energy Development Grants and Loans

Findings

91. The CEDF Board has prohibited projects that have accepted the standard offer, or are seeking to accept the standard offer, from receiving a CEDF grant. Exh. Board-7.

Discussion

Pursuant to Section 8005(b)(2)(B)(i)(I)(aa), the Board must take into account, when setting the standard-offer prices,"reasonably available tax credits and other incentives . . . ." Since the CEDF Board has adopted a policy prohibiting standard-offer projects from accepting CEDF grants, we conclude that this source of funding is not reasonably available and should be excluded from the price determination for all technologies.

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31. This recommendation corresponds to an assumed annual interest rate of 5% charged monthly at a rate of 5/12%. The monthly interest rate is then multiplied by the installed cost over half the average construction lengths of 9 months (for large solar) and 4 months for wind.

32. Rickerson/Karcher pf. reb. at 9.

J. Property Taxes and Insurance

Findings

92. Property taxes should be based on the property's assessed value established by calculating the net present value of the project's annual EBITDA (Earnings before Interest, Taxes, Depreciation and Amortization) value using a property tax capitalization rate. Dalton pf. reb. at 7.

93. The discount rate used for calculating the net present value of the EBITDA included the value of using a property tax capitalization rate (i.e., the project's weighted average before tax cost of capital, depreciation charge factor, and property tax factor). Dalton pf. reb. at 7; exh. Board-JCD-7; exh. REV-MR-MK-5.1/6.

94. The appropriate tax rates (i.e., 1.35% for the education tax rate and 0.43% for the municipal tax rate) are then applied to this property tax basis to establish the annual property tax amount. Dalton pf. reb. at 7.

95. The property tax should be set to reflect the fact that, as the generation asset depreciates and its remaining useful life diminishes, its value declines. Therefore an appropriate approach to use for modeling is to change the annual property tax charges by the product of the inflation rate and the depreciation in value of the generation asset, which is assumed to follow the decline in the asset's useful life. Dalton pf. reb. at 7.

96. The property tax to be applied on a small wind project (15kW) in the first year is $500. The insurance cost to be applied on a small wind project (15kW) in the first year is $500. Exh. Board-JCD-7.

Discussion

REV and the Board's Independent Witness agreed on the method for calculating the property tax for use in the model. The Department agrees with this approach and recommends that the Board use the same approach relied on by REV and Mr. Dalton.[33] The approach appears reasonable and we adopt it.

For purposes of the modeling, then, the property tax should be the product of the combined education and municipal tax rates (1.78%) and the project's net present value of the

33. DPS Brief at 14.

annual EBITDA. This value is then adjusted each year to calculate a new property tax after increasing the property tax by the assumed general inflation rate and reducing it by the assumed property tax depreciation rate that corresponds to the project life. For solar, the property tax depreciation rate should be set at 4%, however, it would be more appropriate to vary the rate based on the estimated project life. Consequently, we recommend that the value for a project with a 20-year life be 5% and a project with a 15-year life project be 6.67%.

The Board's Independent Witness recommends a first year cost for insurance on a 15kW wind project of $500 and a first year property tax of $500. We incorporate these recommendations in our own recommendations to the Board.

K. Tax Depreciation

Findings

97. For wind, REV and the Board's Independent Witness assumed that 95% of the installation costs (hard costs) would be subject to a 5-year Modified Accelerated Cost Recovery System ("MACRS") tax depreciation. Half of the assumed 30% tax credit was removed from the basis of the accelerated depreciation schedule. The remaining installation costs (i.e., 5% of hard costs) were subject to a 15-year MACRS tax depreciation. Exh. REV-MR-MK-5.1; exh. Board-JCD-7.

98. For solar, REV and the Board's Independent Witness assumed that 97.5% of the installation costs (hard costs) would be subject to a 5-year MACRS tax depreciation. Half of the assumed 30% tax credit was removed from the basis of the accelerated depreciation schedule. The remaining installation costs (i.e., 2.5% of hard costs) were subject to a 15-year MACRS tax depreciation. REV's witnesses also assumed a 5-year MACRS tax depreciation for the inverter replacement in the 12th year of operation. Exh. REV-MR-MK-5.1/5.2/6; exh. Board-JCD-7.

99. For projects electing the federal ITC (also the cash 14 grant option), half of the ITC amount must be subtracted from the depreciable basis of the asset. Rickerson/Karcher pf. at 6.

100. All initial "Financing and IDC Costs" received 20-Year MACRS tax depreciation. Exh. REV-MR-MK-5.1.

101. For hydroelectric projects, 10% of the initial capital costs should receive 15-Year MACRS tax depreciation. Ninety percent of the initial capital costs should receive a 20-Year MACRS tax depreciation after a reduction of basis by 50 % for the federal investment tax credit. Exh. Board-JCD-7.

102. For landfill methane projects, 100% of the installation costs (hard costs) should be subject to a 5-year MACRS tax depreciation schedule. Half of the assumed 30% tax credit should be removed from the basis of the accelerated depreciation schedule. Exh. Board-JCD-7.

103. For farm methane projects, two-thirds of the initial capital costs after grants should receive a 20-year MACRS tax depreciation schedule. The remaining one third of initial capital costs after grants should receive a 7-year straight line depreciation. All interconnection expenses should receive a 15-year MACRS tax depreciation schedule. Exh. Board-JCD-7.

104. While holding all other assumptions constant, this modified depreciation schedule increased the required price from $119/MWh to $121/MWh. As cost structures are very project specific, the allocation percentages were meant to be a general representation of a generic project. Rickerson/Karcher pf. at 9.

105. Working capital and reserves should be treated as "non-depreciable" expenses under the model. Exh. Board-JCD-7.

Discussion

The modeling of tax depreciation by the various modelers did not diverge widely and received little focus in testimony. Based on the testimony and the briefs, we conclude that the impacts of these refinements and differences to the analysis appears to have only a modest impact. For the technologies that were modeled by REV's witnesses, the DPS agrees that the more detailed approach to depreciation used by REV's witness was reasonable.[34] The approach used by REV in its modeling is reasonable and we recommend its adoption for use in the modeling.

In other instances, Mr. Dalton's depreciation assumptions were not challenged by either the Department or by the other active participants in this proceeding. We conclude that these assumptions are reasonable and recommend their adoption for purposes of the modeling.

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34. DPS Initial Brief at 14.

L. Interconnection Costs

Findings

106. The generator is responsible for the cost to design and develop the facilities necessary for the safe and reliable interconnection and operation of the project with the host utility's interconnecting electric system. Bowen pf. at 11.

107. Utility interconnection requirements can vary greatly and are determined by such factors as the size of the proposed generator, the generator technology, the strength of the interconnecting distribution line, the topology of the distribution circuit, and the aggregation of additional distributed generation on the circuit. The complexity of the interconnection requirements will typically increase as generator size (individual and in aggregate on the same circuit) increases. Bowen pf. at 11-12; tr. 12/1/09 at 57-58 (Bowen).

108. Interconnection costs can include interconnection equipment and engineering, line construction and upgrade, system protection, metering, and real time communications. Some costs are independent of generation technology while some may be technology or system topology dependent. Bowen pf. at 11.

109. The exact cost for interconnection of a generating facility are site-specific and can only be determined on a case-by-case basis. The following interconnection cost estimates may be considered reasonable for cost modeling purposes: $1000 or less for small projects (less than 50 kW); $125,000 for medium-size projects (50 kW to 500 kW); $175,000 for larger projects (greater than 500 kW). These estimates do not include the costs borne by applicants for interconnection studies, nor the cost for line construction or upgrades that may be required for a particular generator location. Bowen pf. at 17; tr. 12/1/09 at 41, 45-48, and 63-66 (Bowen).

110. Interconnection costs are an integral part of the project costs. Information provided on installed capital costs typically include interconnection costs. Cost information provided on interconnection costs would not be additive to installed capital costs. Tr. 12/1/09 at 39 (Bowen); tr. 12/3/09 at 11-12 and 51 (Becker).

Discussion

Utility interconnection requirements and costs are generally site-specific and can vary by the size of the generation project and location on the electrical system. CVPS provided some interconnection costs based on project size, but recognized that other factors contribute to the determination of interconnection costs. Parties agreed that the costs of interconnection were generally incorporated in the cost modeling as part of the installed capital costs and no additional interconnection costs needed to be added to the project costs. We therefore conclude that the interconnection costs have been adequately included in the cost modeling.

M. Federal Investment Tax Credit

Findings

111. A project's business entity can be structured in ways that allow them to better use the available tax credits. A standard-offer price should be based on the assumption that a project's business structure allows it to take full advantage of the tax credits that are available. Becker pf. at 6.

112. Given the significant portion of project value that is reflected by investment tax credits, it is reasonable to expect developers and investors to develop partnerships and financing vehicles that can efficiently utilize these tax benefits. Dalton pf. reb. at 24.

113. The federal ITC should be fully utilized to recognize the broad federal tax base available to effectively rely on the federal ITC. Dalton pf. reb. at 25.

114. For large wind, a 30% federal investment tax credit based on 95% of the installation costs ("hard costs") of the project should be assumed. Exh. Board-JCD-7; exh. REV-MR-MK-5.1; exh. DPS-4.

115. For large solar, REV and Mr. Dalton recognized a 30% federal investment tax credit based on 97.5% of the installation costs of the project should be assumed. Exh. Board-JCD-7; exh. REV-MR-MK-6.

116. For hydro, a 30 % federal investment tax credit based on 90% of the installation costs of the project should be assumed. Exh. Board-JCD-7; exh DPS-4.

117. For landfill methane, a 30% federal investment tax credit based on 90% of the installation costs of the project is a reasonable assumption. Exh. DPS-4.

118. For farm methane projects, no federal investment tax credit should be included. Exh. DPS-JB-1; exh. Board-JCD-7.

119. For small wind (15kW), a 30% federal investment tax credit based on 82% of the installed costs of a project should be assumed. Exh. Board-JCD-7.

Discussion

Based on the evidence, and the general level of agreement among the financial modelers, we conclude that it is reasonable to assume that a 30% federal investment tax credit is reasonably available and that potential developers can develop strategies for efficiently relying on the tax credit. However, some small level of differences surfaced regarding the proportion of the project's installation or hard costs that might be eligible for the tax credit. Based on the testimony received, we conclude that 97.5% of installed costs for solar projects should be eligible for the credit, 95% of large wind-installed costs should be eligible for credit and 82% of small wind, 90% of the installed costs for hydro and landfill methane projects should be eligible for the credit, and that the federal investment tax credits are generally unavailable to farm methane projects due to the limited tax appetite or taxable income obligations to apply against the credit for such projects.

N. Vermont Investment Tax Credit

Findings

120. For all the models runs, except solar and farm methane, the Department included the Vermont State Investment Tax Credit ("VITC"). Vermont allows individuals and individuals with pass-through income from partnerships and S-Corporations to take 24% of the federal Investment Tax Credit as a tax credit to offset Vermont income. This tax credit should be assumed for all projects except farms and solar projects because the pricing should be based on a well-suited project, which includes factors relating to the appropriate business structure to maximize the opportunity to use available tax credits. The VITC is a non-refunded credit, so a business needs to have taxable income to fully use the credit, it cannot be carried forward. Becker pf. at 7.

121. The Department's analysis assumed on 50% of the tax credit deducted in the first year. Sixty percent of the state investment tax credit was assumed in the first year for the non-solar PV technologies. For wind, REV's experts calculated the Vermont investment tax credit as 50% of the 24% of the federal tax credit. Exh. DPS-JB-1; Dalton pf. reb. at 25; exh. REV-MK-WR-5.1.

122. The model should assume that only 50% of the VITC is utilized in the first year, as opposed to being fully deducted in the first year; the remaining 50% of the VITC should be considered to go unused and provides no tax benefit to the project. The federal ITC is fully deducted in the first year. The VITC is different from the Vermont Business Solar Tax Credit in that the Vermont Business Solar Tax Credit can be carried over for five years independently of the federal ITC. Becker pf. at 5-6.

123. While the VITC cannot be carried over unless the federal ITC is also carried over to future years, the federal ITC is fully utilized in the first year we assume 50% of the VITC can be used and the remaining is lost due to the project's inability to fully utilize the Vermont tax credit in the first year. Becker pf. reb. at 6.

124. Efficiently utilizing the state investment tax credits given the limited pool of Vermont taxpayers that are in the highest marginal tax bracket is a challenge and therefor requires adjustment in the model to temper the assumptions. Dalton pf. reb. at 25.

Discussion

On the basis of the testimony presented, we conclude that the Department has taken reasonable precautions to utilize the VITC for technologies other than solar, which has a separate Business Solar Investment Tax Credit. For purposes of the analysis, we recommend that the Board adopt the Department's approach of applying 50 % of the available VITC to the first year of the projects (when the full Federal Investment Tax Credit is realized for modeling). The Department is also correct in not applying a similar credit to farm methane projects because the assumed tax appetite or taxable income of farm methane projects is inadequate to apply either the Federal or State Investment Tax Credits.

O. Operation and Maintenance Costs

Findings

125. The witnesses presented estimates for operation and maintenance expenses to be incorporated into the price calculation. Exh. Board-JCD-4; exh. DPS-5; exh. REV-WR.

Discussion

Each of the three models incorporates expenses for operations and maintenance ("O&M").[35] The O&M expenses that each party used in its model are different. In general terms, the Department and John Dalton used a lower O&M figure for each category than did REV, although this is not uniform. For the solar category, GMP's testimony on O&M expense was consistent with the Department and Mr. Dalton.[36] Moreover, the figures presented by the Department and Mr. Dalton were consistent with those developed by the Cost Analysis Subgroup in Docket 7523, which formed the basis for our assessment of the reasonableness of the statutory default rates. According to the Department, however, the differences between the witnesses are small and have little affect upon the calculated standard-offer price.[37] The Department, therefore, recommends that the Board average the figures for O&M used by itself, REV and John Dalton.

REV objects to the Department's proposal. REV maintains that the Department's averaging methodology would produce an unreasonable result because the Department's calculation of O&M expense is incorrect; specifically, REV contends that the Department did not adjust the O&M expenses to reflect the higher capacity factors that the Department advocated.

We find the Department's approach to setting O&M expenses in the models reasonable and recommend that the Board adopt it, except for the landfill methane and small wind categories. The witnesses presented different figures for O&M expenses in the models. They did not, however, offer any explanation of the primary factors that produce these differences. We note that, for the most part, the Department's and Mr. Dalton's calculations were consistent with one another and with the O&M expenses that were used to assess the reasonableness of the statutory

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35. Exhs. Board-JCD-4, REV-WR, and DPS-4.
36. Gifford pf. at 9.
37. DPS Brief at 20.

default rates. REV has not explained why, in certain categories, we should accept its higher O&M expense estimates. At the same time, as the Department argues, the effect of the differences between the different O&M cost assumptions on the standard-offer prices themselves are relatively small.

We treat the small wind and landfill methane categories differently. For small wind, only Mr. Dalton presented a calculation of the O&M expense, since the other witnesses based their analyses on 100 kW facilities. Therefore, we accept his figure. For landfill methane, we explain the methodology below.

We are also not persuaded by REV's objection to the averaging methodology. No party, including REV, presented any evidence as whether, and by what amount, O&M expenses would be expected to increase if the Board determined that a higher capacity factor for a particular technology was appropriate. Absent such a showing in the record, we have no basis for concluding that REV's objection has any merit or that any adjustment would be material. In fact, for technologies such as solar power, it is not clear how the capacity factor would have a meaningful effect upon O&M, unless one assumed that the capacity factor could only be attained with a different system that itself had higher costs. No party presented evidence on this issue.

In light of the small differences between the O&M cost estimates, the evidence before us, and the small effect the O&M expense has on the standard-offer prices, averaging the O&M expense figures from the DPS, REV and Mr. Dalton is a reasonable approach. O&M expenses should escalate with inflation after the first year.

P. Debt-Equity Structure and Minimum Debt Service Coverage

Findings

126. The debt-equity ratios used in the Department's models ranged from a 75/25% debt-equity structure for Farm Methane to a 30/70% debt-equity structure for 100 kW wind. For 2.2 MW Solar the DPS relied on a 36/64 debt-equity structure, for 1.5 MW wind the DPS relied on a 41/59 debt-equity structure, for hydro the DPS relied on a 53/47 debt-equity structure, and for landfill gas the DPS relied on a 43/57 debt-equity structure. Exh. DPS-JB-1.

127. The average debt service coverage ratios maintained by the Department's models ranged from a high of 1.8 for landfill gas to a low of 1.21 for farm methane. The minimum debt service coverage ratios ranged from a high of 1.71 for large solar to a low of 1.16 for farm methane projects. Exh. DPS-JB-1.

128. The Department adjusted debt to equity ratios and prices to ensure positive cash flow for all years and sufficient debt service coverage ratios, and to achieve the targeted return on equity ("ROE"). Becker pf. reb. at 2.

129. For project-financed projects, a lender would require that these projects satisfy average debt-service coverage ratios of 1.5 and minimum debt-service coverage ratios of 1.2. Dalton pf. reb. at 14.

130. Farm methane projects were assumed to utilize a more conventional mortgage secured by the property value of the farm (or a portion thereof). Exh. Board-2.

Discussion

The debt-equity structure actually received little attention in the testimony and the financial modelers have not sought direction on this as an input to the data. As the DPS pointed out, the debt-equity structure is a product of the modeling that includes consideration of debt service coverage ratios. The Department indicates that "there are slight differences on this issue but of no impact so there is no real disagreement that the Board needs to decide. If the Board asks to do model re-runs with its assumptions, the final debt-equity ratio will be determined at that time in the final price adjustments of the model."[38] Nevertheless, the Board's Independent Witness included the debt-equity structure and related assumptions among the list of issues that require a Board determination for modeling. REV would like clear direction regarding how debt levels should be sized to maintain required coverage ratios and eliminate years with negative cash flow. (REV Reply Brief at 12). The REV request is reasonable and we offer the following direction.

For purposes of the modeling, we recommend that the project-financed resource category (large solar) maintain debt service coverage ratios that are consistent with the expected practices

38. DPS Initial Brief at 23.

that would apply to project financing. Specifically, the large solar projects should maintain an average debt-service coverage ratio of 1.5 and a minimum of 1.2. All other projects should ensure that the size of debt is used efficiently so long as a positive cash flow is maintained and an average debt-service ratio of 1.5 is maintained. The calculations should also assume escalation of a portion of the standard-offer price, as is described above. The exception is farms, which, given the special nature of the loan, we will require only that a positive cash flow be maintained and that the average debt coverage ratio be maintained above 1.2.

V. Resource-Specific Issues

A. Solar

Findings

131. Despite agreements about the model to be used in developing prices for solar PV projects, agreement does not exist among the witnesses on several key assumptions, most importantly the assumptions pertaining to capacity factor, maintenance reserves, working capital, handling of federal and state investment tax credit, financing costs, installation costs, the debt term (referred to in the model as "loan life"), interest rate (referred to in the model as "debt costs"), inverter replacement costs, inverter conversion efficiency, maintenance costs, and depreciation. Seddon pf. reb. at 2-3; tr. 12/3/09 at 202-203 (Seddon); tr. 12/4/09 at 53-54 (Karcher), 111 (Dalton).

132. The assumptions where disagreement exists that have the largest potential impact on price are capacity factor, annual output degradation, and debt term. Tr. 12/3/09 at 61 (Becker).

Discussion

Direction on issues related to financing, working capital, debt term, interest rates and depreciation were addressed above. The remaining issues are addressed below.

(1) Response to Interim Price Determinations, Granularity

Findings

133. The statutory standard to be applied by the Board in setting the generic prices for each category of resources is "to ensure that the price provides sufficient incentive for the rapid development and commissioning of plants and does not exceed the amount needed to provide such an incentive. 30 V.S.A. § 8005(b)(2)(B)(i)(III).

134. For PV solar projects alone, almost 200 applications were received offering 172 MW on the first day of project eligibility. Dalton pf. reb. at 2.

135. The level of market response clearly suggests that the market believes that the price may be higher than required. Dalton pf. reb. at 2-3.

136. Seventy-four utility-scale applications (those projects with a capacity of one MW or greater) totaled over 138 MW, and applications from 2.2 MW projects alone totaled 92.4 MW. Based on the receipt of proposals from 74 utility-scale projects, the interim rate could have been set to reflect an estimate of the most efficient Vermont solar projects and still have easily met the standard-offer program goals. Gifford pf. at 10.

137. The PV sector is characterized by rapid technological change and significant swings in supply and demand. Current expectations are that the prices of PV modules will decline. Dalton pf. reb. at 3; Gifford pf. at 8.

138. If market conditions change in ways that are not anticipated, then significant project attrition can be expected. Dalton pf. reb. at 4.

139. The interim price of 30 cents/kWh for solar projects elicited accepted applications ranging in size from 26 kW to 2200 kW. Exh. Board-3.

140. The average installed cost of solar projects appears relatively constant above the three or four-hundred kW range and above. Tr. 12/2/09 at 93 (Gifford).

Discussion

The Board established an interim price of 30 cents/kWh on September 15, 2009. The Board made available approximately 12.5 MW of capacity that would be eligible for the interim price by any individual resource category, including solar. Upon opening the standard-offer, the

Speed Facilitator received almost 200 applications for 172 MW of power, which demonstrated a strong demand at the interim price level. At least in the context of solar applications, the Board received some cautionary notes from REV's witnesses who related a significant differential between applications and commissioned projects in Ontario, and from the Board's own SPEED Facilitator, who expressed uncertainty about the likelihood of commissioning for all of the solar projects in the queue.

While we acknowledges these cautionary notes regarding how the significant volume of applications should be interpreted, we agree with the Board's Independent Witness, the Department, and GMP's witness that this volume of applications suggest that the interim PV price was simply set too high relative to the statutory goals. The statute required that the Board set generic price determinations and establish adjustments "as the board determines to be necessary to ensure that the price provides sufficient incentive for the rapid development and commissioning of plants and does not exceed the amount needed to provide such an incentive." Section 8002(2)(B)(i)III. The response to the $0.30/kWh price suggest that we did not meet this statutory directive.

Indeed, the impressive response to the solar prices suggests not only that the price was high, but that smaller and less cost-effective projects responded to these price signals. As Mr. Dalton suggests, this indicates that smaller projects appear to be motivated by factors that may not require returns comparable to utility-scale projects. The testimony of Mr. Gifford suggests that similar cost characteristics exist for solar projects between three-to-four hundred kW capacity, and projects with a capacity up to 2.2 MW. Based on the evidence and the response to date, we are left to conclude that statutory goals for encouraging size diversity in the solar category can be met by establishing a single price for relatively large projects.

(2) Inverter Replacement

Findings

141. The inverter component of a solar facility will need to be replaced or refurbished during the 25-year life of the project. That cost should be included in the economic model. Exh. REV-4 at 5.

142. Mr. Seddon recommended a refurbishment cost of $440,000 or $0.20 per watt in year 12 of the project as a reasonable cost assumption to refurbish the inverter(s). Exh. REV-5.

143. Mr. Gifford recommended a cost of $0.27 per watt or $270 per kW in the 12th year of the project. Exh. GMP-26.

Discussion

There appears to be little difference among the parties on the appropriate inverter efficiency and the differences appear to have a small impact on the resulting prices.[39] Both GMP's expert witness and REV's expert witness demonstrated a sound knowledge of the sector and experience. And both estimates were reasonably close to each other. The differences between the two estimates may be due to the nature of the investment that occurs in the 12th year. GMP's expert based his estimate on an inverter "replacement", where REV's expert referred to the investment in the 12th year as a "refurbishment". Based on the proximity of the estimates and the evidence provided, we recommend the modeling rely on a simple average of the two independent recommendations for a cost of $0.235 per watt or $514,800 for a 2.2 MW project in the 12th year of the project.

(3) Vermont Business Solar Tax Credit

Findings

144. An important factor in setting a price that conforms with the statute, is the treatment of the Vermont Solar Business Tax Credit for projects commissioned after January 1, 2011, the date the tax credit expires. Tr. 12/4/09 at 97 (Dalton).

145. The Vermont Business Solar Tax Credit allows individuals and corporations to take 30% of the installation cost of a solar system as a tax credit for installations on a business property. Becker pf. at 7.

146. The Vermont Business Solar Tax Credit is a non-refundable credit, so a business needs to have a taxable income to fully use the credit, but it can be carried forward up to five years to offset future taxable income. Becker pf. at 7.

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39. DPS Brief at 22 and DPS Brief, at Attachment DPS-1.

147. It is unlikely that a solar project would be economically viable if the standard-offer price assumes inclusion of the Vermont Solar Business Tax Credit, but due to the timing and commissioning of projects, the Vermont Solar Business Tax Credit is unavailable due to its expiration. Tr. 12/4/09 at 97 (Dalton).

148. The Department recommends taking 75% of the available 30% credit deducted over 5 years. The Board's Independent Witness relied on 100% of an effective 21% Vermont Business Solar Investment Tax Credit taken over two years. REV experts relied on 100% of a Vermont Business Solar Investment Tax Credit taken over 5 years. GMP's expert relied on 100% of the Vermont Business Solar Investment Tax Credit taken in the first year. Exh. DPS-JB-1; exh. DPS-4; exh. Board-JCD-7; Dalton pf. reb. at 25; exh. REV-WR-MK-6; exh. GMP-26.

149. A project's business entity can be structured in ways that allow them to better use the available tax credits. A standard-offer price should be based on assuming that a project's business structure allows it to take full advantage of the tax credits that are available. Becker pf. at 6.

150. The Solar Tax Credit is large enough to make a big difference in the price. Tr. 12/3/09 at 58 (Becker).

151. The Vermont Business Solar Tax Credit expires January 1, 2011. 32 V.S.A. § 5930z (as amended by Act 45 Sec. 9c).

Discussion

The Vermont Solar Business Tax Credit should be recognized for purposes of the modeling. The tax credit is due to sunset after January 1, 2011; nevertheless, roughly a year is available to potential developers between now and its expiration. The Vermont Solar Business Tax Credit is one among several other key cost drivers, including installed costs, that may vary substantially over the coming two years and the Board has the opportunity to reset the rates based on cost drivers that exist at the time. This Board can accept a petition from REV or others to revisit the price if indeed the credit expires. Until such time that the Vermont Solar Business Tax Credit expires, the inclusion of the tax credit in the price determination is appropriate to ensure that the price takes into consideration "reasonably available tax credits and other incentives . . . ."[40]

The Department has recommended that, for calculating the standard-offer price, the Board assume that developers will be able to take advantage of 75 % of the available Vermont Solar Business Investment Tax Credit (which is 30 % of the federal credit) over a 5-year period. This approach recognizes that it will be challenging for businesses to take advantage of the full credit in a given year due to a limited Vermont tax liability. We conclude that the Department's treatment of the tax credit is reasonable and we recommend it for purposes of the modeling.

(4) Solar Degradation Factor

Findings

152. REV and GMP assumed an annual degradation factor of 0.50%. Mr. Dalton assumed an annual degradation factor of 0.71%, and the DPS assumed no degradation. Rickerson/Karcher pf. reb. at 11; Dalton pf. reb. at 35; Gifford pf. at 9; tr. 12/4/09 at 136-137 (Lamont).

153. The inclusion of a 0.50% annual degradation factor is an industry standard and is supported by the manufacturers' output warranties. Exhs. GMP-22, GMP-31, GMP-32 at 14-15.

154. The DPS concedes that annual degradation should be included in the model. Tr. 12/3/09 at 136, 137 (Lamont).

Discussion

The Department did not include a degradation factor in its modeling, but conceded that such a factor should be included in the model. After reviewing the testimony, we conclude that it is appropriate to include such a factor and recommend the use of 0.5% per year. This assumption used by both GMP and REV is supported by manufacturers' output warranties. We find the evidence of such degradation compelling and the evidence supporting the numerical recommendations of REV and GMP to be persuasive. We recommend that the Board require an output degradation factor into the solar models equal to 0.5% per year.

40. Section 8005(b)(2)(B)(i)(I).

(5) Solar Capacity Factor and Inverter Efficiency

Findings

155. Of the assumptions where disagreement exists, capacity factor has the largest potential impact on price. Tr. 12/3/09 at 61 (Becker).

156. PVWatts allows estimation of capacity factors for solar facilities using Burlington, Vermont, weather data. Tr. 12/3/09 at 205 (Seddon).

157. There is not a single correct generic capacity factor. Capacity factors are based on the technology used, and the weather station or state the plant is located. Tr. 12/3/09 at 202 (Seddon).

158. The major difference in the PVWatts analysis that produced the 14.9% capacity factor is the assumed efficiency of transformation which was 87.5% in the Department's initial calculations. A scan of the inverter technology performance data supplied by the California Energy Commission reveals many inverters with a conversion efficiency of 95–97.5%. The Department chose an inverter efficiency of 96% to use in its calculations as representative of current technology. The Department's calculations also include an increase in efficiency attributable to a twice-a-year adjustment in the angle of the panels to better track the solar angle. This adjustment to calculate the net capacity factor was done manually, post PVWatts calculation, and produced an overall expected capacity factor of 15.5%. Lamont pf. at 5.

159. Increased inverter efficiency will increase the capacity factor. Tr. 12/3/09 at 117-18 (Lamont).

160. Soiling and system availability were the other two parameters that were changed by the Department in establishing the 14.9% net capacity factor from the PVWatts tool. Tr. 12/3/09 at 117 (Lamont).

161. There are a significant number of inverters that have a much higher efficiency than the 92% that is the default assumption in the PVWatts calculator. Tr. 12/3/09 at 117 (Lamont); exhs. DPS-1, DPS-5.

162. For solar technology, using the calculation methodology supplied on the PVWatts.com site, which includes Burlington, Vermont weather and insolation data, a net capacity factor of 14.9% results. Lamont pf. at 5; exh. DPS-DFL-1.

163. The PVWatts.com site reflects a Burlington location, no shading, optimal tilt, and is a widely-used tool in the industry. Tr 12/2/09 at 98 (Gifford).

164. Based on the Massachusetts Technology Collaborative, capacity factors for solar projects could range from 12% to 15%. Tr. 12/3/09 at 203, 223 (Seddon).

165. Estimates of the cost of a tracking system in Vermont vary. The source relied upon by the Department indicates that they impose an average cost of 50 cents per watt. REV's expert estimates that a tracking system costs approximately a dollar a watt. Exhibit DPS-5; tr. 12/3/09 at 200-201 (Seddon).

166. Assuming a tracking system would also increase the capacity factors calculated by the Board's Docket 7523 Technical Advisor and REV from 14% to 17.5% and 13.4% to 16.8%, respectively. Exhibit DPS-6.

167. In order to model a 25% enhancement to plant output performance, the model needs to include an operation and maintenance cost to make sure the panels are clear of snow. Tr. 12/3/09 at 200 (Seddon).

168. While technically trackers can be mounted on rooftops, in practice rooftop-mounted solar projects do not include trackers. Tr. 12/3/09 at 200 (Seddon).

169. Because of the risk involved in the maintenance of trackers, large systems typically do not rely on them in the northeast. Tr. 12/3/09 at 199 (Seddon).

Discussion

Assumptions related to the use of capacity factors are among the most significant to the modeling determinations related to the price of solar. As described earlier, our goal here is not merely to reflect an average of past practice, but to assume capacity factors based upon a project that uses cost-effective technology and reasonable siting practices. The range of values from Vermont installation, based on REV's witness, was from 12 to 15%. The recommendations for the model ranged from 13.4 to 15.5%.[41] REV's expert indicated that 13.4% is a reasonable

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41. Based on the experience of REV's expert with solar PV plants operating in the Northeast U.S., the capacity factor of 13.4% for a well-designed and constructed plant (operating in Vermont) correlates well with accepted modeling tools such as PVWatts and actual monitored data from existing plants. Seddon pf. reb. at 2. GMP's expert (continued...)

value to assume for a capacity factor based on his experience to date, and that this figure is supported by the PVWatt.com calculator. GMP's expert also recommended a capacity factor of 13.5%, but provided little explanation or analysis for the recommendation.

For its part, the Department recommends a value of 15.5% and suggests that even higher conversion efficiencies can be justified if it is assumed that standard-offer projects will utilize trackers.[42] REV's expert responds that such trackers are not cost-effective in this climate and he does not recommend their use because the trackers are not cost-effective and create additional risks that render them unattractive to most developers of large projects.

All three expert opinions relied, at least in part, on the PVWatts.com tool for calculating an estimate of solar capacity factor. In doing so, the Department notes, for example, that the DC to AC conversion factor used in the REV analysis was only 77%. A contributing factor to the DC to AC conversion is the inverter efficiency, which the Department recommends be set at 96%, rather than the default value of 92%. However, reliance on even this higher inverter efficiency, in isolation, appears to provide a relatively modest contribution to the capacity factor in comparison to the significant differences in capacity factors attributed to the use of trackers. However, other factors are at play and the inverter efficiency can be purchased as high as 97%.

Based on the testimony received, we are unable to recommend that the capacity factor assume reliance on mechanized trackers, as proposed by the Department, and so confine our recommendations to the boundaries of capacity factors articulated by REV's expert (12 to 15%). That said, we are also persuaded that the PVWatts defaults may be conservative. As the Department points out, the inverter efficiencies alone can contribute a material improvement in the capacity factor above the 13.4% recommended by REV's expert. Also, as the Department notes, manual adjustments of the panels can offer a material improvement in the capacity factor with little additional costs. Trackers also represent an area of emerging opportunities.

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41. (...continued)
also relied upon PVWatt.com in establishing his capacity factor recommendation of 13.5%. Tr. 12/2/09 at 98 (Gifford). The Department relied on a value of 15.5%. Exh. DPS-4.

42. According to estimates developed by the Department, a tracking system would increase the capacity factors calculated by the Board's Technical Advisor from Docket 7523 and REV from 14% to 17.5% and 13.4% to 16.8%, respectively. Exhibit DPS-6.

The testimony received suggests that the significant early application response to the interim prices may be tempered by later barriers and realities that could cause some of the projects to not be constructed, even at the $0.30/kWh price. Nonetheless, this market response represents the best indicator of developer interest at the interim price levels that is available; it cannot be ignored as we establish prices over the next two years. Our modeling efforts in Docket 7523 relied on estimates developed using a 14% capacity factor, and resulted in price levels that were in the proximity of the statutory default. Also, as the earlier discussion reflects, the prices we establish here are intended to reflect best practices, efficient investment, and the location of projects in reasonable sites. In light of these factors, we conclude that a capacity factor value of 14.5% is appropriate for use in the calculations and recommend it for purpose of the modeling. This figure falls within the range of values that can result even without reliance on trackers, which remains a developing opportunity in Vermont. This capacity factor level is above that relied in earlier modeling efforts that resulted in the interim price levels.

(6) Solar Capital Costs

Findings

170. The range of capacity factors for solar projects may be from 12% to 15% for systems in Vermont based on issues of how they are sited and the efficiency of the equipment; however, the cost of more efficient equipment to increase the capacity factor also increases the cost of the project. Tr. 12/3/09 at 203 (Seddon).

171. Mr. Giffords recommends the use of an initial project cost of $5 per watt. This value includes both the cost of financing and the initial funding of reserve accounts. Gifford pf. at 9.

172. Mr. Seddon indicates that a "turn-key" cost of building and commissioning a solar plant in Vermont will be $4.52 per watt. Seddon pf. reb. at 3.

173. Mr. Dalton estimated that the current cost of a solar PV installation is $4.75 per watt. Mr. Dalton also provides an estimate that is 10% lower, or $4.275 per watt, based on factors that include the significant market response to interim prices. Dalton pf. reb. at 34.

174. Mr. Lamont indicates that, based on the Department's evaluation of the data, an installed cost of $4.64 per watt should be used for large solar installations. Lamont pf. at 5.

175. Based on the input assumptions provided by Mr. Gifford, who used a 13.5% capacity factor and initial project costs of $5000/kW, GMP determined that the levelized price for solar should be no more than 26 cents/kWh. Castenguay pf. at 6.

176. The data available clearly shows the beginning of a downward trend with respect to the cost of solar equipment. It is difficult to predict the magnitude of solar-installed cost reductions for the remainder of 2009 and 2010. Gifford pf. at 8.

177. In Massachusetts, where month-by-month award data is readily available, the steady decrease in overall prices for solar systems is apparent. Between May, 2009 and September, 2009, the average price for a solar system has decreased by more than $1,300/kW. Gifford pf. at 7.

178. A tracking system imposes a cost of 50 cents to $1 per watt. Exh. DPS-5; tr. 12/3/09 at 200 (Seddon).

Discussion

Four estimates of capital costs were developed by the Board's Independent Witness, GMP's expert, REV's expert, and the Department. The Board's Independent Witness provided two estimates, one that reflects "current PV capital cost" estimates and a second scenario which assumes an additional 10% reduction. The range of estimates for installed capacity cost were actually fairly narrowly bound. Mr. Seddon recommended a value of $4.52 per watt, Mr. Dalton recommended values of $4.75 based on "current value" and, with a 10% reduction, $4.275 to reflect an additional 10% reduction below current value, based on some of the price pressures that are present in the market,[43] and the Department recommended a value of $4.64 per watt. Mr. Gifford's estimate of $5 per watt was higher but included financing and initial funding of reserve accounts. Removing the reserve accounts results in an installed cost of $4.94 per watt. With that adjustment, the estimates reflect a reasonably narrow range.

Given the range of estimates and the significant response that the Board received in response to the interim rates set at 30 cents/kWh, along with current trends and expectations regarding the declining costs of solar systems, we conclude that there is a reasonable basis for

43. Dalton pf. reb. at 35.

conservatism. On this basis, we believe that a value as low as $4.275 presented by Mr. Dalton in his alternate case may be appropriate. However, we are mindful of the tradeoff between the efficiency of the equipment and the increase in capital costs. In the previous section, we assumed a higher capacity factor, which is likely attainable with greater inverter efficiency; the more efficient inverter, however, has higher costs. On that basis, we recommend that the Board adopt a value of $4.75 per watt, which represents Mr. Dalton's estimate of current costs and the middle of the range of estimates provided by GMP, the DPS, REV, and the Board's Independent Witness. This cost input represents only installed costs and excludes financing and the funding of reserve accounts, which are discussed separately.

A summary of the assumptions for solar PV is listed below.

Net Capacity (kW)	2,200
Installed Costs ($/kW)	4,750
1^{st} Year O&M Expense ($/kW)	6.67
Capacity Factor	14.5%
Offsetting Revenue (per year)	0
Debt Term (years)	6 term/18 debt amort
Debt Interest Rate	7.25%
Asset Life	25
Contract Term (years)	25
Degradation Factor (annual)	0.5%
Inverter Replacement (year)	12th
Inverter Cost $	514,800

B. Wind

(1) Small Wind

Findings

179. The Cost Analysis subgroup estimates of project costs included interconnection costs. Tr. 12/3/09 at 12 (Becker).

180. The cost of installation for small wind facilities is approximately $5770 per kW. Exh. DPS-4.

181. A small wind project is unlikely to use project financing, but would more likely be an existing business using the value of the real estate to finance the project. Tr. 12/3/09 at 11 (Becker); exh. Board-3; tr. 12/2/09 at 67 (Basa).

182. The persons that are most likely to develop small wind projects are likely to use a lower discount rate and demand a lower return than other developers. These developers tend to deploy wind turbines smaller than 15 kW because of the environmental benefits from the projects and derive a portion of the return from providing those benefits. For this reason, it is appropriate to adjust the standard-offer price to assume that a lower, 8%, return, would provide adequate incentive for such projects. Tr. 12/4/09 at 115–116, 122 (Dalton).

183. Analysis of capacity factor data for small wind facilities indicates a capacity factor ranging from 17–23%. Rickerson/Karcher pf. at 17; Dalton pf. reb. at 32; exh. DPS-JB-1.

184. The Cost Analysis Subgroup estimated 23.8% as the capacity factor for wind facilities 100 kW or less. The Subgroup did not model projects under 15 kW separately. Exh. Board-1 at 17.

185. A small percentage change in capacity factor can have an impact on the price output of the model. Tr. 12/4/09 at 25 (Karcher).

186. O&M costs for small wind generation facilities are $15/Mwh. Exh. Board-JCD-4.

Discussion

In the September 15, 2009, Order, the Board concluded that there was insufficient basis to alter the 20 cents per kWh statutory default price for wind generation facilities of 15 kW or less. Since the Board opened the standard-offer program on October 19, no wind projects in this category have applied. The absence of applications suggests the possibility that the price did not create sufficient incentive for developers; in this PFD, we have factored the lack of response from developers into our recommendations to the Board.

Capacity Factor

The parties presented a range of estimates for the capacity factor.[44] The Department proposes a capacity factor of 23.8%, which was based upon the report of the Cost Analysis Subgroup. REV recommends a smaller 20% capacity factor, while Mr. Dalton simply proposed a range of 19–23.8%.[45] No party presented detailed evidence to support the calculation of capacity factor.

We recommend that the Board incorporate a capacity factor of 20% for wind facilities in the 15 kW and smaller category. This falls within the range proposed by the parties. We have selected a lower capacity factor at least in part due to the fact

In its brief, REV argues that the Board can only rely upon the testimony of its witness, Mr. Mott, and should discount the testimony of other witnesses who were not wind power developers. We disagree. First, although Mr. Mott advocated a capacity factor of 20%, his testimony suggested that well-sited 100 kW facilities can be expected to achieve capacity factors in excess of that estimate.[46] Second, the testimony of the other witnesses was consistent with the analysis of the Cost Analysis Subgroup, which included a wide range of participants as well as representatives of the parties sponsoring main witnesses.

Installation Costs

One area of disagreement between the witnesses is the installation cost for small wind facilities. Only Mr. Dalton presented testimony specific to the costs of wind generation facilities

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44. It should be noted that the testimony on the small wind (≤15 kW) category related to capacity factor and most other costs were based upon facilities 100 kW or below, and not necessarily targeted to 15 kW wind turbines. In this PFD, we take into consideration the likely differences between 100 kW facilities and the smaller, 15 kW or less, projects, although the evidence for such adjustments is limited, at best.

45. In his calculations, Mr. Dalton used 19% for 15 kW wind projects and 23.8% for 100 kW projects. However, he provided no explanation for the difference.

46. Tr. 12/3/09 at 100 (Mott).

of 15 kW or less, with an installation cost of $6400 per kW. Mr. Dalton, REV and the Department submitted models based upon small wind facilities of 100 kW or less. Here, Mr. Dalton included an installed cost of $6750 per kW, the Department recommended $5770 per kW, and REV proposed $5850 per kW. The Department asserts that much of the difference between the per kW installed cost for wind is attributable to Mr. Dalton's inclusion of interconnection costs. The Department contends that these interconnection costs are subsumed in the installation costs used by the Cost Analysis Subgroup.[47] No other party commented on this difference.

We agree with the Department that interconnection costs would generally be considered to be an element of installation costs. In general, the installation costs for all categories of renewable resources that we have considered in this Docket have encompassed interconnection costs. Neither Mr. Dalton nor any other party has shown that the installed costs used by Mr. Dalton did not already subsume interconnection costs. Therefore, we recommend that the Board adjust Mr. Dalton's installed costs to exclude the interconnection costs, which he stated were $1000 per kW.[48]

We recommend that the Board use the installation costs proposed by the Department. These costs, which are based upon the work of the Cost Analysis Subgroup, are substantially similar to those proposed by REV. Moreover, the Department's installed cost is also reasonably close to Mr. Dalton's adjusted installation costs.

Financing Costs

The parties also disagree on the appropriate financing costs to incorporate for the small wind category. As this PFD explains above, we recommend that the Board conclude that projects in this size category would be unlikely to use project financing.

Mr. Dalton also recommends that we make a further adjustment to the financial costs associated with small wind projects to account for the fact that such projects are likely to have owners with a lower expectation for return on equity. According to Mr. Dalton, the developers most likely to develop wind turbines smaller than 15 kW do so for non-economic reasons; they

47. Tr. 12/3/09 at 12 (Becker) and 208 (Seddon).

48. Dalton pf. reb. at 31.

expect to derive a portion of their return from the environmental benefits. Mr. Dalton, therefore, proposes that the Board adjust the standard-offer price to assume that a lower, 8%, return would provide adequate incentive for such projects.

We recommend that the Board accept Mr. Dalton's proposal to adjust the ROE for the small wind projects, for the reasons he proposes.

Operations and Maintenance

The financial models presented by REV, the Department and Mr. Dalton included O&M expenses. However, the Department's and REV's models were based upon a 100 kW facility; only Mr. Dalton included an O&M expense specific to wind projects of 15 kW or less. We recommend that the Board accept this figure — $15/MWh.

Expansion of 15 kW category to 100 kW

REV argues that the Board should expand the 15 kW category for wind projects to include projects with installed capacity of 100 kW or less. REV asserts that the appropriate dividing line is 100 kW, not the 15 kW specified in the statute.[49]

As we discuss above, we recommend that the Board not set prices for subcategories beyond those set out in the statute. REV has not demonstrated why we should adopt a different approach for wind projects; accordingly, we find no basis for making such an adjustment.

A summary of the assumptions for small wind projects is listed in the table below.

Net Capacity (kW)	15
Installed Cost ($/kW)	5770
1st Year O&M Expense ($/MWh)	15
Capacity Factor	20%
Offsetting Revenue (per year)	0
Debt Term (years)	10
Debt Interest Rate	6%

49. REV Reply Brief at 7–8.

Asset Life (years)	20
Contract Term (years)	20
ROE (%)	8

(2) Large Wind

Findings

187. The price level established for large wind projects with a capacity greater than 15 kW, under the interim prices on September 15, 2009, was 12.5 cents per kWh. Docket 7523, Order of 9/15/09.

188. As of October 30, 2009, there were 12.1 MW of wind projects in the queue for standard offer contracts. Exh. Board-3.

189. The eight projects in the queue as of October 30, 2009, ranged in size from 100 kW to 2.2 MW. The smallest projects under the wind category were 100 kW projects, of which there were two. Six of the eight projects in the queue are for 1.8 MW and above. Exh. Board-3.

Discussion

The interim prices succeeded in attracting 12.1 MW of capacity ranging in size from 100 kW to 2.2 MW. While two applications have been accepted at the 100 kW level, the remainder are at 1.8 MW and above. This suggests that the interim price provides a sufficient incentive for rapid development and commissioning of large wind plants.

(a) Capacity Factor

Findings

190. The Department's experts and the Board's Independent Witness relied on an estimate of 26.6% as the capacity factor appropriate for large scale wind. Exh. DPS-JB-1; exh. Board-JCD-7; exh. Board-1.

191. REV relied on a capacity factor of 25%, and notes that wind plants have a high sensitivity to this assumption and therefore a small difference in the capacity factor is important. Mott pf. at 2.

192. In the 1.5 MW size range, for single units, the range in capacity factors falls between 18 and 30%, based on REV's technical expert's global experience. Tr. 12/3/09 at 94-95 (Mott).

193. Factors other than location on ridge lines, such as local topographic effects, can contribute to capacity factors well above 25% in Vermont. Tr. 12/3/09 at 100 (Mott).

Discussion

The capacity factor recommended by the Department and Mr. Dalton was developed over an extensive period of review and discussion in the earlier (Docket 7523) proceeding. These estimates were developed with the full participation of utility personnel with experience with larger wind projects of this nature, along with the experience of Mr. Dalton. It is clear that, while REV's expert offers considerable expertise and experience, his experience with projects of this size and character in Vermont is limited.[50] Based on the testimony received, we conclude that there are other factors, other than placement on ridge lines, that may result in capacity factors above 25% for projects of this size. For purposes of the assumptions to be used in the modeling of inputs, the range has already been greatly narrowed by the experts. Still, Mr. Mott brings considerable experience to this proceeding and his concerns about the capacity factor of 26.6 cannot be ignored. We recommend that the Board rely on a simple average of the two (25+26.6)/2 or 25.8% for purposes of establishing the price for wind projects above 15 kW.

(b) Installed Costs

Findings

194. The Department of Public Service and the Board's Independent Witness relied on installed costs for large wind projects, assuming a capacity of 1.5 MW, of $3000/kW. Exh. DPS-JB-1; Dalton pf. reb. at 32; exh. Board-JCD-7; exh. Board-1.

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50. As Mr. Mott noted, he has worked on just one project between the size of 100 kW and 1.5 MW that were not net metered projects.

Discussion

There is little material difference between the estimate of installed costs used by the Board's Independent Witness and the Department, and the estimate provided by REV.[51] The major difference between the two estimates related to the reserve accounts and the financing and costs associated with interest during construction. These costs are addressed, for all categories of projects, separately above. With respect to the installed costs, we recommend that the Board rely on the estimates provided by the Department and Mr. Dalton. This estimate was developed in the context of the earlier efforts in Docket 7523. After reviewing the record, this value appears to enjoy general support for the current modeling efforts. For purposes of modeling, we recommend an installed cost of $3000/kW for wind projects over 15 kW.

(c) Life of the Large Wind Project

Findings

195. The Board's Independent Witness relied on a 25-year life for the 1.5 MW project modeled as a large wind project. Dalton pf. reb. at 33; exh. Board-JCD-7.

Discussion

The Board's Independent Witness recommends and relied on a 25-year life for larger wind projects.[52] There is little impact from a change to the life of a wind project, while holding other aspects of the modeling constant. The change only affects the residual project revenues, which, for purpose of the model, is assumed to offset the decommissioning costs of the project, and a component of the property tax capitalization calculation used in determining the annual property tax rates. For purposes of the modeling, we recommend that the asset life be recognized as 25 years based on guidance from the Board's Independent Witness. The standard offer contract

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51. REV's experts relied on an installed cost of $3087/kW ($4,630,000/1500 kW) and a total project cost including reserve accounts, financing and interest during construction ("IDC") of $3292/kW. Rickerson/Karcher pf. reb. at exh. REV-WR-MK-5.1.

52. The Department and REV relied on a 20-year life for the 1.5 MW project to be modeled as a large wind project. Exh. DPS-JB-1; exh. REV-MR-MK-5.1.

term and the depreciation rate assumptions shall be unchanged from the term already established and the recommendations for the depreciation rate established above.

A summary of the assumptions for large wind are listed in the table below.

Net Capacity (kW)	1,500
Installed Costs ($/kW)	3,000
1st Year O&M Expense ($/kW)	46
Capacity Factor	25.8%
Offsetting Revenue ($per year)	$0
Debt Term (years)	18
Debt Interest Rate	7.25%
Asset Life (years)	25
Contract Term (years)	20

C. Landfill Methane

Findings

196. The September 15 Order established an initial standard offer price of 12 cents per kWh for landfill methane projects, using the statutory default price established by Act 45. The September 15 Order concluded that, given the limited information available, the Department's modeling, and comparable projects in other jurisdictions, the statutory rate should apply. Docket 7523, Order of 9/15/09 at 36.

197. Three landfill methane projects applied for the standard-offer program, with proposed sizes of 150 kW, 560 kW, and 1,000 kW. The 1,000 kW project proposes to use waste heat off an existing landfill project. Tr. 12/4/09 at 62 and 65 (Spencer); exh. Board-3.

198. An assessment of available data on landfills in Vermont anticipates two distinct classes of potential new projects that might generate additional electricity from landfill methane in Vermont: (1) expansion of existing projects through installation of additional engines, most likely in unit sizes of 1.6 MW nameplate capacity per engine, to match the existing engines at each active landfill site; and (2) development of smaller projects, most likely at or below 200 kW in

nameplate capacity, at closed landfills that have existing landfill gas collection systems and flares, or other small closed landfills. Smith pf. at 4; exh. GMP-1.

199. It is possible that existing landfill gas projects ("LFG") might be expanded by supplementing the landfill methane by fuel from another source, such as biogas fuel produced by the anaerobic digestion of organic wastes in new facilities to be developed at or adjacent to the landfills. Smith pf. at 5.

200. The most cost-effective potential LFG project configuration in Vermont is based on a 1,600 kW nameplate internal combustion engine. The existing Coventry and Moretown LFG projects each are based on multiple 1,600 kW nameplate engines. Expansions of these projects would likely use the same-sized engines, or somewhat smaller ones on the order of 800 kW to 1,000 kW. Smith pf. at 5-6.

201. Generally, the lower per-kW costs of these larger projects reflect both the economies of scale that results from the larger size of the generating equipment (engines and turbines) and the ability to spread development costs, landfill gas collection system costs, interconnection costs, control system costs, site improvements, and other infrastructure costs over a larger number of kW. Smith pf. at 7.

202. The small LFG projects in Vermont would likely use small internal combustion engines that are refurbished and outfitted with special features to run on landfill methane. The approach of refurbishing small internal combustion engines to run on landfill gas has been used by CommonWealth Resource Management Corporation ("CRMC") at its 200 MW project in Lowell, Massachusetts, and by other developers for multiple projects in New England. Smith pf. at 13-15.

203. The U.S. Landfill Methane Outreach Program's LFG Energy Project Development Handbook indicates typical annual capital costs of $1,700 per kW for large internal combustion engines of 800 kW or greater and $2,300 per kW for small internal combustion engines of 1 MW or less. Smith pf. at 6; exh. GMP-2 at 4-5.

204. A December 2008, press release from contractor SCS Engineers indicates that a 3.2 MW LFG project in DeKalb, Georgia, was developed for a capital cost of $5 million, or roughly $1,600/kW. Smith pf. at 7; exh. GMP-4.

205. WEC's recent Coventry LFG project was developed for an estimated capital cost of roughly $2,000/kW, and features projected long-term costs of about 5 cents/kWh. Smith pf. at 8; exh. GMP-5.

206. The capital costs for CRMC's 3.3 MW project in New Bedford, Massachusetts, was less than $1,850/kW. Smith pf. at 8; exh. GMP-16 at 3.

207. Based on CRMC experience, a project capital cost of $2,000/kW or less should be achievable for those utilizing 1.5 MW class engines and small, refurbished engines. This capital cost includes direct purchase and installation costs for the engine and generator set, along with allowances for interconnection, development and permitting. Smith pf. at 8-9 and 15; exh. GMP-16 at 1-2.

208. CRMC LFG cost modeling assumes an operating cost of $30 per MWh for small projects and $20 MWh for large expansion projects. Mr. Dalton made the same assumptions. Exh. GMP-16 at 1; exh. Board-JCD-4.

209. The LFG Energy Project Development Handbook indicates that typical annual O&M costs are $180 per kW for large internal combustion engines and $210 per kW for small internal combustion engines.[53] Exh. GMP-11 at 4-5.

210. The LFG Energy Project Development Handbook assumes a 15-year project life for landfill gas projects. Exhs. GMP-11 at 4-4 and GMP-12.

211. CRMC LFG cost modeling assumes a 15-year project life. Exh. GMP-16 at 3.

212. Landfill gas projects currently in operation typically achieve capacity factors over 90%. An annual capacity factor of 90% would represent an operational project, taking into account hourly and daily variations in landfill gas availability and methane content, and downtime for scheduled maintenance and annual overhauls. Smith pf. at 11; exh. GMP-16 at 1.

213. Landfill methane projects are a stable power source that produce in a baseload fashion. The high capacity rating has significant financial value in the New England capacity market or during peak hours of electricity use. This production profile improves the relative

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53. These O&M costs are equivalent to $18 per MWh for large combustion engines and $22 per MWh for small combustion engines, assuming 90% capacity factor.

cost-effectiveness of this resource for customers, and complements other renewable sources that produce intermittently. Smith pf. at 13; tr. 12/2/09 at 119 (Smith).

Discussion

The September 15 Order established an initial standard-offer price of 12 cents per kWh for landfill methane projects, using the statutory default price in Act 45.[54] Limited information was available for cost modeling, and initial project modeling assumed a project net capacity of 132 kW and an installed capital cost of $4,818/kW, and resulting in a standard offer price of 25.4 cents/kWh. The Department's model runs assumed a net project capacity of 132 kW, the same installed capital cost of $4,818/kW, and lower O&M costs, and resulting in a standard-offer price of 12.9 cents/kWh. The September 15 Order concluded that, given the limited information available, the Department's modeling, and comparable projects in other jurisdictions, the statutory rate should apply.

GMP has provided additional information on project size, capacity, and costs for use in the Board's review of the rate set in the September 15 Order. GMP has gathered information from U.S. Landfill Methane Outreach Program's LFG Energy Project Development Handbook and CRMC to use in the development of standard-offer price for landfill methane projects.

Analysis of landfill availability indicates that, besides the expansion of existing landfill gas projects, most new development will come from smaller projects, most likely at or below 200 kW in nameplate capacity, at closed landfills that have existing landfill gas collection systems and flares, or other small closed landfills. The three landfill methane projects that applied for the standard-offer program had proposed sizes of 150 kW, 560 kW, and 1,000 kW. The Department's cost modeling assumed a plant capacity of 132 kW.[55] Both GMP and the Board's Independent Witness concluded that a separate standard-offer price may be appropriate for small landfill projects.[56] Cost modeling for landfill methane projects by the Board's Independent Witness assumed a plant capacity of 600 kW for small landfill projects and 1,500 kW for large

54. Docket 7523, Order of 9/15/09 at 36.
55. Exh. DPS-JB-1.
56. Smith pf. at 12-13; Dalton pf. reb. at 30.

projects. In setting standard offer prices, the standard-offer price should be based on the largest, efficient new landfill methane project size that is likely to be implemented in Vermont. Given the information on landfill availability, we are recommending that the cost modeling be based on a small landfill plant size of 200 kW.

Both GMP and the Board's Independent witness recommended a capital cost of $2,000 per kW that reflects all project installation costs including development, interconnection, and financing costs, as well as any relevant debt service and operating reserves.[57] The Department's cost modeling included a capital cost of $2,300 per kW based on the recommended costs for small landfill projects contained in the LFG Energy Project Development Handbook.[58] While the LFG Energy Project Development Handbook presented capital costs that ranged between $1,700 and $2,300 per kW based on project size, CRMC cost modeling assumed the same capital costs for large and small projects. Given the CRMC conclusion that small internal combustion engines can be refurbished to run on landfill gas, and that these costs are similar to a large combustion engine, a capital cost of $2,000 per kW appears to be reasonable and achievable for most landfill methane projects. Therefore, we recommend that the cost modeling be based on a capital cost of $2,000 per kW.

The Board's Independent witness recommended an O&M cost of $20 per MWh for large landfill methane projects and $30 per MWh for small projects.[59] The Department's cost modeling included an O&M cost of $57 per MWh.[60] CRMC LFG cost modeling assumed an operating cost of $30 per MWh for small projects and $20 MWh for large projects and the LFG Energy Project Development Handbook indicates that typical annual O&M costs are $18 per MWh for large internal combustion engines and $22 per MWh for small internal combustion engines.[61] Given the recommendation that the cost modeling be based on landfill capacity size of 200 kW and CRMC project experience operating a 200 kW landfill methane project, an O&M cost of $30 per

57. Smith pf. at 10; Dalton pf. at 29.
58. Becker pf. reb. at 8.
59. Dalton pf. at 30.
60. Becker pf. reb. at 8.
61. The LFG Energy Porject O&M costs assume 90% capacity factor.

MWh appears to be reasonable and achievable. Therefore, we recommend that the cost modeling for landfill methane projects be based on an O&M cost of $30 per MWh.

GMP and the Board's Independent witness recommended a capacity factor of 90% and the Department recommended a capacity factor of 90.25%.[62] Landfill gas projects in current operation typically achieve capacity factors over 90% and are typically a source of baseload power. Given current landfill capacity factors and the participants' agreement, we recommend that the cost modeling for landfill methane projects be based on a capacity factor of 90%.

The Board's Independent witness recommended a project life of 20 years and the Department recommended a project life of 15 years.[63] The LFG Energy Project Development Handbook and CRMC LFG cost modeling assume a 15-year project life for landfill gas projects. The methane produced from landfills can diminish over time, especially at closed landfills. We recommend that the cost modeling for landfill methane projects be based on a 15-year project life.

A summary of the assumptions for landfill methane is listed in the table below.

Net Capacity (kW)	200
Installed Costs ($/kW)	2000
1st Year O&M Expense ($/MWh)	30
Capacity Factor	90%
Offsetting Revenue (per year)	0
Debt Term (years)	13
Debt Interest Rate	7.25%
Asset Life (years)	15
Contract Term (years)	15

62. Dalton pf. at 30; exh. DPS-JB-1.
63. Dalton pf. at 30; exh. DPS-JB-1.

D. Farm Methane

The statutory default price for the farm methane projects was set at $0.12/kWh. In the Board's September 15 Order establishing interim prices, this figure was adjusted to $0.16/kWh. Within the first week of opening the standard-offer program, 14 farm methane projects applied for the standard offer.[64] The number of applications suggests a significant amount of interest in the standard-offer program at the $0.16/kWh price. In addition, it is worth noting that several farm methane projects were developed prior to the implementation of the standard-offer program, at rates significantly below $0.16/kWh.[65]

Findings

214. Farm methane projects would likely be financed using conventional real estate loans with the collateral based on farm real estate. Accordingly, a ten-year debt term, with a cost for debt of 5.5.%, is a reasonable assumption for farm methane projects. Dalton pf. at 14; Becker pf. at 5.

215. Due to the economic conditions of the farms hosting farm methane projects, the model assumes that tax credits are not available for these projects. Accordingly, the model should also assume that, for farm methane projects, there are no cash flow requirements to meet federal and state income tax obligations. Becker pf. at 8-9; Dalton pf. reb. at 9.

216. A two-tiered price for farm methane projects, that would include higher payments in the first ten years of the contract to meet debt-service requirements and lower prices in the following ten years of the contract, after these debt-service requirements have been met, will increase the potential for projects to default once farm methane projects begin receiving the lower price. Dalton pf. reb. at 9-10.

217. Since CEDF grants will no longer be available for standard-offer projects, the Department recommends removing $139,950 in CEDF grants from the $578,313 figure that represents the assumed available grants for farm methane projects. This results in a net of

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64. Tr. 12/4/09 at 64 (Spencer).

65. *See,* Dockets 6977 (Petition of Blue Spruce Farm, Inc.), 7200 (Petition of Berkshire Cow Power, LLC), 7179 (Petition of Green Mountain Dairy Farm, LLC), 7266 (Petition of David R. and Cathy J. Montagne), 7413 (Petition of Neighborhood Energy, LLC). *See also,* Docket 7578, Order of 12/8/09, *Investigation into Amendment of Central Vermont Public Service Corporation's Voluntary Renewable Pricing Program.*

$438,363, or $1461/kW. Letter of December 16, 2009, from Sarah Hofmann, Esq., to Susan M. Hudson, Clerk of the Board; exh. Board-7.

Discussion

Several of the modeling assumptions for farm methane projects differ from other resource categories, largely due to the fact that the farm methane projects are directly tied to the underlying farm. Therefore, certain assumptions, such as taxable income and available debt terms, differ from projects that fit within the more traditional definition of a commercial enterprise.

The Department proposed a two-tiered rate for farm methane projects that would allow a sufficient price during the loan repayment years to meet the debt service requirements and allow a lower rate during the non-debt service period of the contract to benefit ratepayers while still allowing the farm methane project to earn the specified ROE.[66]

The Board's Independent Witness stated that, while the two-tiered price structure recommended by the Department will result in a lower overall levelized cost, two-tiered pricing results in increased front loading of prices to farm methane projects. After discussing the increased potential for default once the lower-tier price is received, the Board's Independent Witness concluded: "I don't believe that the lower overall price (as measured in terms of levelized costs) offered by two-tier pricing is sufficient compensation for the increased risk of project defaults."[67] We accept the Independent Witness's conclusion and recommend that the Board not institute two-tiered pricing for farm methane projects.

The Department and the Board's Independent Witness filed proposed assumptions needed to model the farm methane price. These assumptions were not disputed by any party and we adopt these assumptions, with the exception of the assumption regarding available grant funding, as further described below. The assumptions we adopt are set out in the Table below.

The assumptions are largely the same as those used to establish the September 15 interim price. One important distinction is the availability of CEDF grants for farm methane projects. As discussed earlier, these grants are no longer available for projects going forward; accordingly, the

66. Becker pf. at 10.

67. Dalton pf. reb. at 9-10.

assumption that $1,928 per kW reflects reasonable available grants is incorrect. On December 16, 2009, the Department filed information that the average CEDF grant per farm methane project was $139,950.

The Department's December 16 filing included a motion requesting that we allow the figure of $139,950 into the record so that amount can be removed from the modeling of the farm methane prices. No party filed comments on the Department's motion. Given that such information is necessary to make an informed decision regarding the standard-offer price for farm methane projects, and no party has objected to the inclusion of this information, we admit this information into the evidentiary record. The resulting grant levels assumed are therefore set at $438,363, or $1461/kW.

Section 8005 requires us to set cost-based prices for qualifying SPEED resources, but also includes the following provision:

> The board shall include such adjustment to the generic costs and rate of return on equity determined under subdivisions ((2)(B)(i)(I) and (II) of this subsection as the board determines to be necessary to ensure that the price provides sufficient incentive for the rapid development and commissioning of plants and does not exceed the amount needed to provide such an incentive.[68]

In the September 15 interim price Order, the Board cited to this statutory provision to adjust the price for farm methane projects:

> Because the statutory criteria expressly exclude offsetting revenues or benefits from RECs or the sale of RECs in the initial calculation of costs for farm methane projects, such an offset was ultimately excluded from the model inputs used by the Board for its determination. Nevertheless, Act 45 permits the Board to make adjustments of those costs to ensure that the price is set to encourage rapid deployment but no more than is necessary to do so. Given the preliminary nature of our modeling and the fact that projects are being actively developed at lower rates than those suggested by the model, we conclude that a rate that does not include the offset of revenues from renewable energy credits ("RECs") would likely be excessive.[69]

Given that the majority of the assumptions used to model farm methane projects remain unchanged, except for the availability of CEDF grants, the exclusion of which is likely to increase

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68. Section 8005(b)(2)(B)(i)(III).

69. Docket 7523, Order of 9/15/09 at 38.

the price, it is appropriate for the Board to utilize the above-cited statutory provision to again bring the price into line with the requirement that the price "does not exceed the amount needed to provide such an incentive."

The Board should also take into consideration the fact that a number of farm methane projects were developed or proposed prior to the implementation of the standard-offer program.[70] These projects were compensated at prices consistent with the market, rather than the higher rates set out in the September 15 Order (and adopted here).

A summary of the assumptions for farm methane is listed in the table below.

Net Capacity (kW)	300
Installed Costs ($/kW)	7,628
Grant ($/kW) before tax	1,461
1st Year O&M Expense ($/kW) (includes staffing)	767
Capacity Factor	76.5%
Offsetting Revenue ($per year)	95,000
Debt Term (years)	10
Debt Interest Rate	5.5%
Asset Life (years)	20
Contract Term (years)	20

E. Biomass

The statutory default price for biomass projects was set at $0.125/kWh. In our September 15 Order establishing interim prices, we concluded that there was insufficient information to make an adjustment to this figure. On the first day that the SPEED Facilitator began accepting applications, the total capacity of biomass projects applying under the standard-offer program was

70. *See,* Docket 7578, Order of 12/8/09, *Investigation into Amendment of Central Vermont Public Service Corporation's Voluntary Renewable Pricing Program.*

15.7 MW, significantly exceeding the 12.5 MW cap for any one technology.[71] This implies that there was a significant amount of interest in the standard-offer program at the $0.125/kWh price.

Findings

218. Given the significant response to the standard-offer price of $0.125/kWh, there is insufficient justification to set the price for biomass resources higher than the existing $0.125/kWh. Dalton pf. reb. at 40.

Discussion

The only party to provide specific cost information regarding biomass projects was REV and its testimony was not for the category as a whole, but only for one specific technology. In prefiled testimony sponsored by REV, prices of $0.296/kWh and $0.574/kWh, depending on whether the biomass project had an annual or seasonal thermal load profile, were proposed. However, REV's proposed findings did not advocate specific numbers for biomass resources. Instead, REV proposed:

> There is sufficient evidence in the current record to compel a conclusion that biomass facilities using wood as a fuel are a separate category of technology requiring its own price under the statute. However, the record now before the Board is insufficient to establish the appropriate price other than the existing price set on September 15, 2009. Therefore, REV requests the Board to open a separate inquiry upon REV's (or another party's) petition when better cost information exists, but utilizing the testimony and modeling from this Docket where appropriate, in order to gather the evidence necessary to set an appropriate price under the statute. In the interim, the Board should retain a price of 12.5 cents until a new price is determined.[72]

REV's testimony raises a number of concerns. First, it is not clear that the specific cost data REV sponsored, which was based upon a proposed project, adequately captured all benefits of the project. For example, the prices did not include the value of a biomass project's thermal

71. Dalton pf. reb. at 2.

72. REV Initial Brief at 6-7.

output, which, according to REV's witness, is a significant portion of the overall project benefits.[73] Without such information, we cannot develop a meaningful price for biomass.

Second, and more significantly, even if we were to conclude that the $0.296/kWh and $0.574/kWh prices initially proposed by REV could be supported by the evidentiary record, it is still limited to one specific biomass technology. The significant response to the standard-offer price of $0.125/kWh would suggest that other biomass technologies are more cost-effective and should form the basis for the standard-offer price. The fact that the applications for biomass facilities filled the 12.5 MW subcap on the first day, combined with the statutory directive to ensure that the standard-offer prices not exceed the amount needed to provide incentive for rapid deployment,[74] compels us to conclude that the default price of $0.125/kWh provides sufficient incentive.

The lack of reliable data to establish a new price for biomass resources leads us to conclude that the statutory default prices should be maintained until such time as there is sufficient information to develop an alternative price. We recommend that the Board retain the $0.125/kWh price until the next statutory review process, unless a party petitions the Board to alter the number before that time.

F. Hydro

Findings

219. The price established for hydro under the interim prices on September 15, 2009, was 12.5 cents per kWh. Docket 7523, Order of 9/15/09.

220. As of October 30, 2009, there were 6.7 MW of hydro projects in the queue for standard offer contracts. Exh. Board-3.

221. The nine projects in the queue as of October 30, 2009, ranged in size from 50 kW to 2.2 MW. Including the 50 kW project, there were two hydroelectric projects at or below 100 kW. Exh. Board-3.

222. The Department's model re-run produced a result of $129/Mwh. Becker pf. at 4.

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73. Tr. 12/2/09 at 154 (Maker).

74. Section 8005(b)(2)(B)(i)(III).

223. Key assumptions used in the Department's analysis, and that of the Board's Independent Witness, were a capacity factor of 44.9%, an installed cost of $4173/kW, and a fixed operation and maintenance cost of $162/kW on a 1.278 MW unit. Exh. DPS-JB-1; Dalton pf. reb. at 33.

Discussion

The interim prices succeeded in attracting 6.8 MW of hydro capacity. The capacity in the queue reflects a diverse mix of size, consistent with statutory goals.

There were no disputes related to hydro that emerged based on the analysis. We approve the assumptions relied on by the Department and the Board's Independent Witness for purposes of the analysis. The Board should apply the above inputs to the cost analysis, combined with the other determinations in establishing a modeled cost for hydro based on the assumed plant size of a 1.278 MW facility.

The hydro recommendations are summarized below.

Net Capacity (kW)	1.278
Installed Costs ($/kW)	4173
1st Year O & M Expense ($/kW)	$101
Capacity Factor	44.9%
Offsetting Revenue (per year)	$0
Debt Term (years)	18
Debt Interest Rate	7.25%
Asset Life (years)	30
Contract Term (years)	20

VI. Conclusion and Summary of Assumptions for Modeling

We recommend that the Board accept the input assumptions set forth in the PFD and adopt, for use in the standard-offer program, the prices that are derived from the models based upon those inputs. The specific input assumptions are set forth in an Attachment to this Proposal for Decision.

Dated at Montpelier, Vermont, this ________ day of __________________, 2010.

____
J. Riley Allen
Hearing Officer

____
George E. Young
Hearing Officer

VII. ORDER

IT IS HEREBY ORDERED, ADJUDGED AND DECREED by the Public Service Board of the State of Vermont that:

1. The findings and recommendations of the Hearing Officers are accepted.
2. Effective immediately, the standard-offer for renewable power under 30 V.S.A. § 8005(b)(2) shall be as specified in this Decision.

Dated at Montpelier, Vermont, this ______ day of _____________, 2010.

______________________________	)	
	)	PUBLIC SERVICE
	)	
______________________________	)	BOARD
	)	
	)	OF VERMONT
______________________________	)	

OFFICE OF THE CLERK

FILED:

ATTEST:____

Clerk of the Board

NOTICE TO READERS: This decision is subject to revision of technical errors. Readers are requested to notify the Clerk of the Board (by e-mail, telephone, or in writing) of any apparent errors, in order that any necessary corrections may be made. (E-mail address: psb.clerk@state.vt.us)

Appeal of this decision to the Supreme Court of Vermont must be filed with the Clerk of the Board within thirty days. Appeal will not stay the effect of this Order, absent further Order by this Board or appropriate action by the Supreme Court of Vermont. Motions for reconsideration or stay, if any, must be filed with the Clerk of the Board within ten days of the date of this decision and order.